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

EI801-11-AR

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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 2011/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be 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 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 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).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

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

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

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

b) 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 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	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

e) The following format must be used for the CPA Certification Statement 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."

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

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC 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. The public reporting burden for the FERC 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: Information Clearance Officer); 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 Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

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 submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

EXCERPTS FROM THE LAW

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

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(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 shall 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 and 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 fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt 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 FERC Form or FERC 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

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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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 2011/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)* 299 First Avenue North, St. Petersburg, FL 33701	
05 Name of Contact Person Cynthia S. Lee	06 Title of Contact Person Manager-Reg/Prop Accounting
07 Address of Contact Person *(Street, City, State, Zip Code)* 299 First Avenue North, St. Petersburg, FL 33701	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(727) 820-5535	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Mark Mulhern	Mark S Mulhern Mark Mulhern	04/05/2012
02 Title Chief Financial Officer		

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 Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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".

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".

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 12/31/2011	Year/Period of Report End of 2011/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.

Jeffrey M. Stone
Vice President of Accounting
412 S. Wilmington Street
Raleigh, NC 27601

Florida Power Corporation
299 First Avenue North
St. Petersburg, FL 33701

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	12/31/2011	End of 2011/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	12/31/2011	End of 2011/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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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	12/31/2011	End of 2011/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 Chief Executive Officer	Vincent M. Dolan	1,679,977
2			
3	Senior Vice President and Chief Financial Officer	Mark F. Mulhern	2,675,140
4			
5	Chairman	William D. Johnson	9,514,688
6			
7	Executive Vice President	Jeffrey J. Lyash	2,375,230
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9	Executive Vice Presdient and Chief Compliance Officer	John R. McArthur	2,035,664
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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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 104.1 Line No.: 1 Column: a

Page 104 discloses the compensation of the individual who served as the Chief Executive Officer (CEO) of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (PEF) during the year ended December 31, 2011, along with the compensation of the individual who served as PEF's Chief Financial Officer and the three most highly compensated executive officers other than the CEO and CFO who were serving as executive officers as of December 31, 2011. These individuals were identified in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission.

Schedule Page: 104.1 Line No.: 1 Column: c

Total compensation, including salary, for 2011 received by the CEO, CFO and the other three most highly compensated executives is determined in accordance with Item 402 of Regulation S-K as promulgated by the Securities and Exchange Commission. Progress Energy, Inc.'s (Progress Energy) executive officers serve as officers and/or directors of its various subsidiaries, including PEF. They have multiple responsibilities within and provide various services to Progress Energy and its subsidiaries. The compensation of Progress Energy's executive officers is designed to cover the full range of services they provide to Progress Energy and its subsidiaries. It is not the policy of Progress Energy to allocate compensation paid to its executive officers among the various subsidiaries to which they provide services.

Schedule Page: 104.1 Line No.: 3 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104.1 Line No.: 3 Column: c

See footnote at line 1 Column C.

Schedule Page: 104.1 Line No.: 5 Column: a

See footnote at line 1 Column A.

Schedule Page: 104.1 Line No.: 5 Column: c

See footnote at line 1 Column C.

Schedule Page: 104.1 Line No.: 7 Column: a

See footnote at Line 1 Column A.

Schedule Page: 104.1 Line No.: 7 Column: c

See footnote at Line 1 Column C.

Schedule Page: 104.1 Line No.: 9 Column: a

See footnote at line 1 Column A.

Schedule Page: 104.1 Line No.: 9 Column: c

See footnote at line 1 Column C.

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	12/31/2011	End of 2011/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	Vincent Dolan	P.O. Box 14042, St. Petersburg, FL 33701
2	President and CEO	
3		
4	William D. Johnson	P.O. Box 1551, Raleigh, NC 27602
5	Chairman	
6		
7	Michael Lewis	P.O. Box 14042, St. Petersburg, FL 33701
8	Senior Vice President	
9		
10	Jeffrey J. Lyash	P.O. Box 1551, Raleigh, NC 27602
11	Executive Vice President	
12		
13	John R. McArthur	P.O. Box 1551, Raleigh, NC 27602
14	Chief Financial Officer	
15		
16	Mark F. Mulhern	P. O. Box 1551, Raleigh, NC 27602
17	Chief Financial Officer	
18		
19	Paula Sims	P. O. Box 1551, Raleigh, NC 27602
20	Senior Vice President	
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25	***Florida Power Corporation has no Executive Committee	
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Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[ ] Yes
[X] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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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	12/31/2011	End of 2011/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?	[ ] Yes [X] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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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	12/31/2011	End of 2011/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/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 104 or 105 of the Annual Report Form No. 1, 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 first quarter ending March 31, 2011 three new franchise agreements were signed and approved by city ordinances. The Treasure Island agreement passed on 1/18/11, city of Belleair Beach agreement passed on 2/7/11 and the city of Belleair Bluffs agreement passed on 2/28/11. The prior agreements with these three cities were scheduled to expire in 2011. The new agreements have a ten-year term and a 6% fee.

During the second quarter ending June 30, 2011 five new franchise agreements were signed and approved by city ordinances. The city of Monticello franchise agreement passed on 4/5/11, the city of Belleview franchise agreement passed on 6/7/11, the city of North Redington Beach franchise agreement passed on 6/9/11, the city of St. Pete Beach and South Pasadena franchise agreements passed on 6/14/11. The prior franchise agreements with these five cities were scheduled to expire in 2011. The new agreements have a ten-year term and a 6% fee.

During the third quarter ending September 30, 2011 one new franchise agreement was signed and approved by city ordinance. The city of Madeira Beach franchise agreement passed on 7/26/11. The prior franchise agreement with the city was scheduled to expire in 2011. The new agreement has a ten-year term and a 6% fee.

During the fourth quarter ending December 31, 2011 three new franchise agreements were signed and approved by city ordinance. The city of High Springs franchise agreement passed on 11/3/11, city of Indian Rocks Beach franchise passed on 11/8/11, and city of Deltona franchise agreement passed on 12/12/11. The prior franchise agreements with each of the cities were scheduled to expire in early 2012. The three new agreements have a 6% fee payable to the municipality. Indian Rocks Beach and Deltona have a ten-year term and High Springs has a fifteen-year term.

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

During the quarter ended March 31, 2011 Florida Power Corporation issued $42,800,000 and redeemed $42,800,000 in commercial paper. The outstanding balance was $0.00, and the weighted average yield issued during the period was 0.35%.

During the quarter ended June 30, 2011 Florida Power Corporation issued $917,400,000 and redeemed $850,600,000 in commercial paper. The outstanding balance was $66,800,000, and the weighted average yield issued during the period was 0.34%.

During the quarter ended September 30, 2011, Florida Power Corporation issued $1,112,000,000.00 and redeemed $1,178,800,000.00 in commercial paper. The outstanding balance on September 30, 2011, was $0.00, and the weighted average yield issued during the period was 0.37%.

During the quarter ended December 31, 2011, Florida Power Corporation issued $588,252,000.00 and redeemed $355,340,000.00 in commercial paper. The outstanding balance on December 31, 2011, was $232,912,000.00, and the weighted average yield issued during the period was 0.45%.

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

Effective March 28, 2011, Non-Bargaining unit employees received a 3% merit increase. Wages increased approximately $4.2 million per year.

Effective December 5, 2011, Bargaining unit employees received a 2.5% increase. Wages increased approximately $3.3 million per year.

9. LEGAL PROCEEDINGS

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter ended March 31, 2011.

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida

Power Corporation Report on Form 10-Q for the quarter ended June 30, 2011.

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-Q for the quarter ended September 30, 2011.

See Part II, Item 1. Legal Proceedings in the Progress Energy, Inc./Carolina Power & Light Company/Florida Power Corporation Report on Form 10-K for the year ended December 31, 2011.

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

1st Quarter Officer Changes:

Elected – Carol C. Nelson, Vice President, 1/1/2011

Director changes: None

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	12/31/2011	End of 2011/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	13,496,722,998	13,190,725,920
3	Construction Work in Progress (107)	200-201	1,148,814,516	966,834,559
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		14,645,537,514	14,157,560,479
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,066,838,645	4,919,393,761
6	Net Utility Plant (Enter Total of line 4 less 5)		9,578,698,869	9,238,166,718
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	79,308	75,539
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		252,489,600	168,406,133
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	105,710,022
10	Spent Nuclear Fuel (120.4)		46,879,386	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	72,118,867	80,115,391
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		227,329,427	194,076,303
14	Net Utility Plant (Enter Total of lines 6 and 13)		9,806,028,296	9,432,243,021
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		10,267,096	10,809,073
19	(Less) Accum. Prov. for Depr. and Amort. (122)		7,118,115	6,275,244
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	23,655,750	28,014,671
24	Other Investments (124)		2,077,614	2,211,709
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		596,287,101	590,973,263
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)		0	3,354,275
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		625,169,446	629,087,747
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		13,653,081	15,752,414
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	232,098,643
39	Notes Receivable (141)		36,923	41,804
40	Customer Accounts Receivable (142)		234,904,708	296,601,262
41	Other Accounts Receivable (143)		99,461,297	137,513,127
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		17,826,565	25,499,419
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		18,795,883	10,662,991
45	Fuel Stock (151)	227	357,584,860	350,104,163
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	292,647,283	271,475,133
49	Merchandise (155)	227	0	402,450
50	Other Materials and Supplies (156)	227	526,917	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	27,243,966	33,389,505

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	12/31/2011	End of 2011/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		23,655,750	28,014,671
54	Stores Expense Undistributed (163)	227	8,603,207	8,606,921
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)		25,733,736	19,619,801
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		941,207	8,726
60	Rents Receivable (172)		282,634	58,032
61	Accrued Utility Revenues (173)		55,187,903	87,499,861
62	Miscellaneous Current and Accrued Assets (174)		123,200,000	140,441,556
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)		4,799,101	13,670,550
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	3,354,275
67	Total Current and Accrued Assets (Lines 34 through 66)		1,222,120,391	1,561,078,574
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		44,464,357	45,804,109
70	Extraordinary Property Losses (182.1)	230a	2,090,175	5,098,978
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	2,297,508,601	1,749,573,126
73	Prelim. Survey and Investigation Charges (Electric) (183)		20,817,157	10,860,643
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	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	44,085,372	44,833,905
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)		16,880,501	18,243,610
82	Accumulated Deferred Income Taxes (190)	234	918,946,903	618,811,877
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		3,344,793,066	2,493,226,248
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		14,998,111,199	14,115,635,590

Schedule Page: 110 Line No.: 5 Column: d

In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as Other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1. The amount of the adjustment for 2010 is $65,840,613.

Schedule Page: 110 Line No.: 72 Column: d

In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as other Regulatory Assets (account 182.3), rather than as adjustgments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1. The amount of the adjustment for 2010 is $65,840,613.

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	12/31/2011	end of 2011/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)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		31,115	31,115
7	Other Paid-In Capital (208-211)	253	1,402,648,736	1,395,967,528
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)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	2,945,334,989	3,143,813,758
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	220
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)	-26,659,142	-3,988,273
16	Total Proprietary Capital (lines 2 through 15)		4,709,257,713	4,923,726,363
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,340,865,000	4,340,865,000
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	150,000,000	150,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		8,918,093	9,059,934
24	Total Long-Term Debt (lines 18 through 23)		4,481,946,907	4,481,805,066
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		189,241,685	198,789,382
27	Accumulated Provision for Property Insurance (228.1)		134,635,569	135,961,982
28	Accumulated Provision for Injuries and Damages (228.2)		47,554,175	43,985,672
29	Accumulated Provision for Pensions and Benefits (228.3)		556,478,706	482,692,295
30	Accumulated Miscellaneous Operating Provisions (228.4)		101,520,776	102,855,788
31	Accumulated Provision for Rate Refunds (229)		63,240	237,127
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		231,460,058	190,128,238
34	Asset Retirement Obligations (230)		368,854,604	350,602,642
35	Total Other Noncurrent Liabilities (lines 26 through 34)		1,629,808,813	1,505,253,126
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		232,912,000	0
38	Accounts Payable (232)		344,742,435	422,521,171
39	Notes Payable to Associated Companies (233)		8,206,378	8,564,944
40	Accounts Payable to Associated Companies (234)		24,928,043	59,594,674
41	Customer Deposits (235)		223,577,438	218,471,851
42	Taxes Accrued (236)	262-263	-4,594,856	-47,287,562
43	Interest Accrued (237)		53,685,323	83,104,116
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) [X] An Original (2) [ ] A Resubmission	12/31/2011	end of 2011/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)		13,783,410	16,513,400
48	Miscellaneous Current and Accrued Liabilities (242)		78,167,610	58,150,390
49	Obligations Under Capital Leases-Current (243)		9,547,698	8,867,228
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		499,757,654	377,756,834
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		231,460,058	190,128,238
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,253,253,075	1,016,128,808
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,695,243	1,544,596
57	Accumulated Deferred Investment Tax Credits (255)	266-267	4,091,516	5,414,515
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	37,398,153	19,037,267
60	Other Regulatory Liabilities (254)	278	695,415,760	497,257,963
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	3,757,590	3,757,590
63	Accum. Deferred Income Taxes-Other Property (282)		1,376,442,607	964,138,005
64	Accum. Deferred Income Taxes-Other (283)		805,043,822	697,572,291
65	Total Deferred Credits (lines 56 through 64)		2,923,844,691	2,188,722,227
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		14,998,111,199	14,115,635,590

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	12/31/2011	End of 2011/Q4

STATEMENT OF INCOME

Quarterly

1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

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	4,369,042,300	5,253,982,000		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,129,655,876	3,520,880,078		
5	Maintenance Expenses (402)	320-323	216,538,240	220,248,642		
6	Depreciation Expense (403)	336-337	336,548,951	326,580,571		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-405,265	2,053,167		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	4,519,490	3,144,525		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-915	-276,440		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		442,090,811	638,639,579		
13	(Less) Regulatory Credits (407.4)		832,040,087	802,027,640		
14	Taxes Other Than Income Taxes (408.1)	262-263	352,660,392	361,778,872		
15	Income Taxes - Federal (409.1)	262-263	-65,117,214	-43,797,196		
16	- Other (409.1)	262-263	8,345,732	-4,290,596		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	460,976,486	357,140,026		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	228,289,991	24,927,696		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,323,000	-1,545,996		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		18,317,624	19,334,751		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		3,842,477,130	4,572,934,647		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		526,565,170	681,047,353		

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

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
4,369,042,300	5,253,982,000					2
						3
3,129,655,876	3,520,880,078					4
216,538,240	220,248,642					5
336,548,951	326,580,571					6
-405,265	2,053,167					7
4,519,490	3,144,525					8
-915	-276,440					9
						10
						11
442,090,811	638,639,579					12
832,040,087	802,027,640					13
352,660,392	361,778,872					14
-65,117,214	-43,797,196					15
8,345,732	-4,290,596					16
460,976,486	357,140,026					17
228,289,991	24,927,696					18
-1,323,000	-1,545,996					19
						20
						21
						22
						23
18,317,624	19,334,751					24
3,842,477,130	4,572,934,647					25
526,565,170	681,047,353					26

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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)		526,565,170	681,047,353		
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)		22,535,743	21,723,002		
34	(Less) Expenses of Nonutility Operations (417.1)		10,876,489	11,262,747		
35	Nonoperating Rental Income (418)		-740,311	-795,430		
36	Equity in Earnings of Subsidiary Companies (418.1)	119		220		
37	Interest and Dividend Income (419)		182,798	597,376		
38	Allowance for Other Funds Used During Construction (419.1)		31,549,740	28,298,437		
39	Miscellaneous Nonoperating Income (421)		13,911,835	1,953,478		
40	Gain on Disposition of Property (421.1)		2,436,111	-5,092,219		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		58,999,427	35,422,117		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		34,650	8,933		
44	Miscellaneous Amortization (425)		778,707	785,846		
45	Donations (426.1)		1,830,416	9,191,821		
46	Life Insurance (426.2)		-397,561	-2,720,922		
47	Penalties (426.3)		166,889	-676,805		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		3,160,835	3,554,084		
49	Other Deductions (426.5)		21,960,546	1,818,397		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		27,534,482	11,961,354		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	53,428	52,430		
53	Income Taxes-Federal (409.2)	262-263	5,233,764	217,158		
54	Income Taxes-Other (409.2)	262-263	-3,482,921	339,208		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	15,333,204	17,796,768		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	12,226,934	24,346,583		
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)		4,910,541	-5,941,019		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		26,554,404	29,401,782		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		246,218,093	248,559,251		
63	Amort. of Debt Disc. and Expense (428)		5,880,015	5,398,285		
64	Amortization of Loss on Reaquired Debt (428.1)		1,363,109	1,363,109		
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)		35,652	178,682		
68	Other Interest Expense (431)		-128,815	15,546,420		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,646,487	13,487,623		
70	Net Interest Charges (Total of lines 62 thru 69)		238,721,567	257,558,124		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		314,398,007	452,891,011		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		314,398,007	452,891,011		

Schedule Page: 114 Line No.: 6 Column: h

In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as Other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1. The amount of the adjustment for 2010 is $65,840,613.

Schedule Page: 114 Line No.: 13 Column: h

In FERC Docket ER11-3584-000, dated July 15, 2011. the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 0900079-EI, March 5, 2010 and June 18, 2010, as Other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1. the amount of the adjustment for 2010 is $65,840,613.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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		3,143,813,758	2,743,646,222
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Section 199 Deduction and Unrealized Tax Benefit/Expense		-1,364,916	(1,211,395)
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		-1,364,916	(1,211,395)
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		314,398,007	452,890,791
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		-510,000,000	(50,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-510,000,000	(50,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		2,945,334,989	3,143,813,758
	APPROPRIATED RETAINED EARNINGS (Account 215)			
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	12/31/2011	End of 2011/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)
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)		2,945,334,989	3,143,813,758
	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)			220
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			220

FOOTNOTE DATA

Schedule Page: 118 Line No.: 4 Column: c

The adjustment for section 199 is recorded to account 216 but does not affect account 439. The offsetting account(s) is(are) 236.

Schedule Page: 118 Line No.: 9 Column: c

See footnote for p.118, Line 4, column (c)

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	12/31/2011	End of 2011/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)	314,398,007	452,891,011
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	337,596,994	327,681,244
5	Amortization of Limited and Electric Plant, Nuclear Fuel, Load Mgmt	14,089,212	11,813,485
6	Amortization of Debt Premium, Expense and Loss on Acquisition	8,230,628	6,498,195
7	(Gain) Loss on Sale of Assets, Other Adjustments to Net Income	375,828,867	123,143,078
8	Deferred Income Taxes (Net)	235,792,766	325,662,515
9	Investment Tax Credit Adjustment (Net)	-1,323,000	-1,545,996
10	Net (Increase) Decrease in Receivables	69,172,412	-113,825,368
11	Net (Increase) Decrease in Inventory	-28,131,006	6,027,404
12	Net (Increase) Decrease in Allowances Inventory	6,145,539	10,264,559
13	Net Increase (Decrease) in Payables and Accrued Expenses	-33,166,796	144,671,768
14	Net (Increase) Decrease in Other Regulatory Assets	-264,034,569	-141,938,715
15	Net Increase (Decrease) in Other Regulatory Liabilities	-67,783,834	187,328,145
16	(Less) Allowance for Other Funds Used During Construction	31,549,740	28,298,437
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote): Change in Current Assets	17,796,572	-19,269,683
19	Change in Other, Net	-187,876,707	-87,248,145
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	765,185,345	1,203,855,060
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-823,724,002	-1,042,593,928
27	Gross Additions to Nuclear Fuel	-14,984,027	-37,512,836
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-5,415,938	-3,173,053
30	(Less) Allowance for Other Funds Used During Construction	-31,549,740	-28,298,437
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-812,574,227	-1,054,981,380
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	133,265	911,786
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-125,000	-225,000
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)	-4,435,310,291	-6,385,769,029
45	Proceeds from Sales of Investment Securities (a)	4,437,524,193	6,389,732,935

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	12/31/2011	End of 2011/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):	102,875,884	63,775,689
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-707,476,176	-986,554,999
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	295,917,227	590,937,888
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	232,912,000	
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	528,829,227	590,937,888
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-300,000,000	-300,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote): Decrease in Intercompany Notes	-357,286	-212,434,726
77	Other Financing	-8,867,227	-11,610,996
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock	-1,511,859	-1,511,859
81	Dividends on Common Stock	-510,000,000	-50,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-291,907,145	15,380,307
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-234,197,976	232,680,368
87			
88	Cash and Cash Equivalents at Beginning of Period	247,851,057	15,170,689
89			
90	Cash and Cash Equivalents at End of period	13,653,081	247,851,057

Schedule Page: 120 Line No.: 4 Column: c

$65,840,613 was reclassified in the prior year from Change in Other Regulatory Assets to Depreciation and Depletion for consistency with current year presentation.

Schedule Page: 120 Line No.: 14 Column: c

$65,840,613 was reclassified in the prior year from Change in Other Regulatory Assets to Depreciation and Depletion for consistency with current year presentation.

Schedule Page: 120 Line No.: 19 Column: b

Change in Other, Net includes the following:

Change in Other Assets and Deferred Debits:	$ (11,104,720)
Change in Accrued Pension and Other Benefits:	(136,676,631)
Change in Other Liabilities and Deferred Credits:	(6,912,973)
Payments for the Termination of Interest Rate Hedges:	(33,182,383)
Total Other, Net	$(187,876,707)

Schedule Page: 120 Line No.: 19 Column: c

Change in Other, Net includes the following:

Change in Other Assets and Deferred Debits:	$ (9,890,605)
Change in Accrued Pension and Other Benefits:	(60,723,618)
Change in Other Liabilities and Deferred Credits:	(16,633,922)
Total Other, Net	$(87,248,145)

Schedule Page: 120 Line No.: 53 Column: b

Other Investing includes the following:

Insurance Proceeds:	$ 75,570,070
Legal Settlement Proceeds:	27,305,814
Total Other Investing	$102,875,884

Schedule Page: 120 Line No.: 53 Column: c

Includes $63,775,689 of insurance proceeds

Schedule Page: 120 Line No.: 77 Column: b

Other Financing includes ($8,867,227) of capital lease payments

Schedule Page: 120 Line No.: 77 Column: c

Other Financing includes the following:

Capital Lease Payments	$ (8,239,321)
Debt Issuance Costs	(3,768,106)
Other	396,431
Total Other Financing	$(11,610,996)

Schedule Page: 120 Line No.: 90 Column: c

Includes $232,098,643 of Temporary Cash Investments

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

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.

Florida Power Corp 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 certain items including but not limited to (1) the reporting of amounts gross or net, (2) the classification of short-term and long-term portions of assets or liabilities, (3) the classification of transactions as operating or non-operating income, (4) the classification of cost of removal obligations and (5) the classification of restricted cash. Please refer to the 10-K footnotes attached below for details.

PEF's Notes to Financial Statements have been combined with Progress Energy, Inc. and Carolina Power and Light Company d/b/a Progress Energy Carolinas, Inc. 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 (receipts) for interest and income taxes for the twelve months ended December 31, 2011 were $287 million and ($83) million, respectively.

PROGRESS ENERGY, INC.
CAROLINA POWER & LIGHT COMPANY d/b/a/ PROGRESS ENERGY CAROLINAS, INC.
FLORIDA POWER CORPORATION d/b/a PROGRESS ENERGY FLORIDA, INC.

COMBINED NOTES TO FINANCIAL STATEMENTS

In this report, Progress Energy, which includes Progress Energy, Inc. holding company (the Parent) and its regulated and nonregulated subsidiaries on a consolidated basis, is at times referred to as "we," "us" or "our." When discussing Progress Energy's financial information, it necessarily includes the results of PEC and PEF (collectively, the Utilities). The term "Progress Registrants" refers to each of the three separate registrants: Progress Energy, PEC and PEF. The information in these combined notes relates to each of the Progress Registrants as noted in the Index to the Combined Notes. However, neither of the Utilities makes any representation as to information related solely to Progress Energy or the subsidiaries of Progress Energy other than itself.

1. <u>ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES</u>

A. ORGANIZATION

PROGRESS ENERGY

The Parent is a holding company headquartered in Raleigh, N.C., subject to regulation by the Federal Energy Regulatory Commission (FERC).

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity. The Corporate and Other segment primarily includes amounts applicable to the activities of the Parent and Progress Energy Service Company, LLC (PESC) and other miscellaneous nonregulated businesses (Corporate and Other) that do not separately meet the quantitative disclosure requirements as a reportable business segment. See Note 20 for further information about our segments.

PEC

PEC is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. PEC's subsidiaries are involved in insignificant nonregulated business activities. PEC is subject to the regulatory jurisdiction of the North Carolina Utilities Commission (NCUC), Public Service Commission of South Carolina (SCPSC), the United States Nuclear Regulatory Commission (NRC) and the FERC.

PEF

PEF is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in west-central Florida. PEF is subject to the regulatory jurisdiction of the Florida Public Service Commission (FPSC), the NRC and the FERC.

B. BASIS OF PRESENTATION

These financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP), including GAAP for regulated operations. The financial statements include the activities of the Parent and our majority-owned and controlled subsidiaries. The Utilities are subsidiaries of Progress Energy, and, as such, their financial condition and results of operations and cash flows are also consolidated, along with our nonregulated subsidiaries, in our consolidated financial statements. Intercompany balances and transactions have been eliminated in consolidation.

Noncontrolling interests in subsidiaries along with the income or loss attributed to these interests are included in noncontrolling interests in both the Consolidated Balance Sheets and in the Consolidated Statements of Income. The results of operations for noncontrolling interests are reported on a net of tax basis if the underlying subsidiary is structured as a taxable entity.

Unconsolidated investments in companies over which we do not have control, but have the ability to exercise influence over operating and financial policies, 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. Other investments are stated principally at cost. These equity and cost method investments are included in miscellaneous other property and investments in the Consolidated Balance Sheets. See Note 13 for more information about our investments.

Our presentation of operating, investing and financing cash flows combines the respective cash flows from our continuing and discontinued operations as permitted under GAAP.

These combined notes accompany and form an integral part of Progress Energy's and PEC's consolidated financial statements and PEF's financial statements.

Certain amounts for 2010 and 2009 have been reclassified to conform to the 2011 presentation.

C. CONSOLIDATION OF VARIABLE INTEREST ENTITIES

We consolidate all voting interest entities in which we own a majority voting interest and all variable interest entities (VIEs) for which we are the primary beneficiary. We determine whether we are the primary beneficiary of a VIE through a qualitative analysis that identifies which variable interest holder has the controlling financial interest in the VIE. The variable interest holder who has both of the following has the controlling financial interest and is the primary beneficiary: (1) the power to direct the activities of the VIE that most significantly impact the VIE's economic performance and (2) the obligation to absorb losses of, or the right to receive benefits from, the VIE that could potentially be significant to the VIE. In performing our analysis, we consider all relevant facts and circumstances, including: the design and activities of the VIE, the terms of the contracts the VIE has entered into, the nature of the VIE's variable interests issued and how they were negotiated with or marketed to potential investors, and which parties participated significantly in the design or redesign of the entity.

PROGRESS ENERGY

Progress Energy, through its subsidiary PEC, is the primary beneficiary of, and consolidates an entity that qualifies for rehabilitation tax credits under Section 47 of the Internal Revenue Code. Our variable interests are debt and equity investments in the VIE. There were no changes to our assessment of the primary beneficiary for this VIE during 2009 through 2011. No financial or other support has been provided to the VIE during the periods presented.

The following table sets forth the carrying amount and classification of our investment in the VIE as reflected in the Consolidated Balance Sheets at December 31:

(in millions)	**2011**	2010
Miscellaneous other property and investments	**$ 12**	$ 12
Cash and cash equivalents	**1**	-
Prepayments and other current assets	**-**	1
Accounts payable	**-**	5

The assets of the VIE are collateral for, and can only be used to settle, its obligations. The creditors of the VIE do not have recourse to our general credit or the general credit of PEC, and there are no other arrangements that could expose us to losses.

Progress Energy, through its subsidiary PEC, is the primary beneficiary of two VIEs that were established to lease buildings to PEC under capital lease agreements. Our maximum exposure to loss from these leases is a $7.5 million mandatory fixed price purchase option for one of the buildings. Total lease payments to these counterparties under the lease agreements were $2 million annually in 2011, 2010 and 2009. We have requested the necessary information to consolidate these entities; both entities from which the necessary financial information was requested declined to provide the information to us, and, accordingly, we have applied the information scope exception provided by GAAP to the entities. We believe the effect of consolidating the entities would have an insignificant impact on our common stock equity, net earnings or cash flows. However, because we have not received any financial information from the counterparties, the impact cannot be determined at this time.

PEC

See discussion of PEC's variable interests in VIEs within the Progress Energy section.

PEF

PEF has no significant variable interests in VIEs.

D. SIGNIFICANT ACCOUNTING POLICIES

USE OF ESTIMATES AND ASSUMPTIONS

In preparing consolidated financial statements that conform to 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 consolidated financial statements, and amounts of revenues and expenses reflected during the reporting period. Actual results could differ from those estimates.

REVENUE RECOGNITION

We recognize revenue when it is realized or realizable and earned when all of the following criteria are met: persuasive evidence of an arrangement exists; delivery has occurred or services have been rendered; our price to the buyer is fixed or determinable; and collectability is reasonably assured. We recognize electric utility revenues as service is rendered to customers. Operating revenues include unbilled electric utility base revenues earned when service has been delivered but not billed by the end of the accounting period. The amount of unbilled revenues can vary significantly from period to period as a result of numerous factors, including seasonality, weather, customer usage patterns and customer mix. Customer prepayments are recorded as deferred revenue and recognized as revenues as the services are provided.

Periodically, we are permitted to start charging customers for proposed rate increases prior to receiving final approval from our regulatory authorities. Such amounts charged are subject to refund upon issuance of the final rate order. In addition, we may be required to refund amounts to customers for previously recognized revenues, through approved orders or settlement agreements, which are not related to proposed rate increases. We recognize revenue subject to refund when it is earned, and separately establish a reserve for amounts that could be refunded when it is probable that revenue will be refunded to customers. See Note 8C for discussion of revenue to be refunded in connection with the 2012 settlement agreement.

FUEL COST DEFERRALS

Fuel expense includes fuel costs and other recoveries that were previously deferred through fuel clauses established by the Utilities' regulators. These clauses allow the Utilities to recover fuel costs, fuel-related costs and portions of purchased power costs through surcharges on customer rates. These deferred fuel costs are recognized in revenues and fuel expenses as they are billable to customers.

EXCISE TAXES

The Utilities collect from customers certain excise taxes levied by the state or local government upon the customers. The Utilities account for sales and use tax on a net basis and gross receipts tax, franchise taxes and other excise taxes on a gross basis.

The amount of gross receipts tax, franchise taxes and other excise taxes included in operating revenues and taxes other than on income in the statements of income for the years ended December 31 were as follows:

(in millions)	2011	2010	2009
Progress Energy	**$ 315**	$ 345	$ 333
PEC	**110**	119	108
PEF	**205**	226	225

RELATED PARTY TRANSACTIONS

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with FERC regulations. The costs of the services are billed on a direct-charge basis, whenever possible, and on allocation factors for general costs that cannot be directly attributed. In the subsidiaries' financial statements, billings from affiliates are capitalized or expensed depending on the nature of the services rendered.

UTILITY PLANT

Utility plant in service is stated at historical cost less accumulated depreciation. We capitalize all construction-related direct labor and material costs of units of property as well as indirect construction costs. The cost of renewals and betterments is also capitalized. Maintenance and repairs of property (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 generally occur every two years. Maintenance activities under long-term service agreements with third parties are capitalized or expensed as appropriate as if the Utilities had performed the activities. Generally, the cost of units of property replaced or retired, less salvage, is charged to accumulated depreciation. For generating facilities to be retired or abandoned significantly before the end of their useful lives, the net carrying value is reclassified from plant in service, net to other utility plant, net when it becomes probable they will be retired or abandoned. When such facilities are removed from service, the remaining net carrying value is then reclassified to regulatory assets in accordance with the expected ratemaking treatment. Removal or disposal costs that do not represent asset retirement obligations (AROs) are charged to a regulatory liability.

Allowance for funds used during construction (AFUDC) represents the estimated 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. Both the debt and equity components of AFUDC are noncash amounts within the Consolidated Statements of Income. The equity funds component of AFUDC is credited to other income, and the borrowed funds component is credited to interest charges.

Nuclear fuel is classified as a fixed asset and included in the utility plant section of the Consolidated Balance Sheets. Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service.

DEPRECIATION AND AMORTIZATION – UTILITY PLANT

Substantially all depreciation of utility plant other than nuclear fuel is computed on the straight-line method based on the estimated remaining useful life of the property, adjusted for estimated salvage (See Note 5A). Pursuant to their rate-setting authority, the NCUC, SCPSC and FPSC can also grant approval to accelerate or reduce depreciation and amortization rates of utility assets (See Note 8).

Amortization of nuclear fuel costs is computed primarily on the units-of-production method and included within fuel used in electric generation in the Consolidated Statements of Income.

FEDERAL GRANT

The American Recovery and Reinvestment Act, signed into law in February 2009, contains provisions promoting energy efficiency (EE) and renewable energy. On April 28, 2010, we accepted a grant from the United States Department of Energy (DOE) for $200 million in federal matching infrastructure funds in support of our smart grid initiatives. PEC and PEF each will receive up to $100 million over a three-year period as project work progresses. The DOE will provide reimbursement for 50 percent of allowable project costs, as incurred, up to the DOE's maximum obligation of $200 million. Projects funded by the grant must be completed by April 2013.

In accounting for the federal grant, we have elected to reduce the cost basis of select smart grid projects. As the select capital projects are placed into service, this will reduce depreciation expense over the life of the assets. Reimbursements by the DOE are deferred as a short-term or long-term liability on the Consolidated Balance Sheets based on their expected date of application to the select projects. Reimbursements related to capital projects are included in other investing activities in the Statement of Cash Flows when cash is received.

ASSET RETIREMENT OBLIGATIONS

AROs are legal obligations associated with the retirement of certain tangible long-lived assets. The present values of retirement costs for which we have a legal obligation are recorded as liabilities with an equivalent amount added to the asset cost and depreciated over the useful life of the associated asset. The liability is then accreted over time by applying an interest method of allocation to the liability. Accretion expense is included in depreciation, amortization and accretion in the Consolidated Statements of Income. AROs have no impact on the income of the Utilities as the effects are offset by the establishment of regulatory assets and regulatory liabilities in order to reflect the ratemaking treatment of the related costs.

CASH AND CASH EQUIVALENTS

We consider cash and cash equivalents to include unrestricted cash on hand, cash in banks and temporary investments purchased with an original maturity of three months or less.

RECEIVABLES, NET

We record accounts receivable at net realizable value. This value includes an allowance for estimated uncollectible accounts to reflect any loss anticipated on the accounts receivable balances. The allowance for uncollectible accounts reflects our estimate of probable losses inherent in the accounts receivable, unbilled revenue, and other receivables balances. We calculate this allowance based on our history of write-offs, level of past due accounts, prior rate of recovery experience and relationships with and economic status of our customers.

INVENTORY

We account for inventory, including emission allowances, using the average cost method. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials reserves are established for excess and obsolete inventory.

REGULATORY ASSETS AND LIABILITIES

The Utilities' operations are subject to GAAP for regulated operations, 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, the Utilities record 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 Consolidated Balance Sheets as regulatory assets and regulatory liabilities (See Note 8A). Management continually assesses whether regulatory assets are probable of future recovery by considering factors such as applicable regulatory changes and recent rate orders applicable to other regulated entities. Additionally, management continually assesses whether any regulatory liabilities have been incurred. The regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process.

NUCLEAR COST DEFERRALS

PEF accounts for costs incurred in connection with the proposed nuclear expansion in Florida in accordance with FPSC regulations, which establish an alternative cost-recovery mechanism. PEF is allowed to accelerate the recovery of prudently incurred siting, preconstruction costs, AFUDC and incremental operation and maintenance expenses resulting from the siting, licensing, design and construction of a nuclear plant through PEF's capacity cost-recovery clause. Nuclear costs are deemed to be recovered up to the amount of the FPSC-approved projections, and the deferral of unrecovered nuclear costs accrues a carrying charge equal to PEF's approved AFUDC rate. Unrecovered nuclear costs eligible for accelerated recovery are deferred and recorded as regulatory assets in the Consolidated Balance Sheets and are amortized in the period the costs are collected from customers.

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. We perform our annual goodwill impairment test as of October 31 each year and perform an interim test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. Intangible assets are 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 the Utilities are amortized over the applicable lives using the straight-line method consistent with ratemaking treatment (See Note 8A).

INCOME TAXES

We and our affiliates file a consolidated federal income tax return. The consolidated income tax of Progress Energy is allocated to PEC 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 carryover of uncompensated tax benefits, which primarily relate to deferred synthetic fuels tax credits. Income taxes are provided for as if PEC and PEF filed separate returns.

Deferred income taxes have been provided for temporary differences. These occur when the book and tax carrying amounts of assets and liabilities differ. 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 fuels are deferred 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) of discontinued operations in the Consolidated Statements of Income. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority, including resolutions of any related appeals or litigation processes, based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount of the tax benefit that, in our judgment, is greater than 50 percent likely to be realized. Interest expense on tax deficiencies and uncertain tax positions is included in net interest charges, and tax penalties are included in other, net in the Consolidated Statements of Income.

DERIVATIVES

GAAP requires that an entity recognize all derivatives as assets or liabilities on the balance sheet and measure those instruments at fair value, unless the derivatives meet the GAAP criteria for normal purchases or normal sales and are designated as such. We generally designate derivative instruments as normal purchases or normal sales whenever the criteria are met. If normal purchase or normal sale criteria are not met, we will generally designate the derivative instruments as cash flow or fair value hedges if the related hedge criteria are met. We have elected not to offset fair value amounts recognized for derivative instruments and related collateral assets and liabilities with the same counterparty under a master netting agreement. Certain economic derivative instruments (primarily fuel-related) receive regulatory accounting treatment, under which unrealized gains and losses are recorded as regulatory liabilities and assets, respectively, until the contracts are settled. Cash flows from derivative instruments are generally included in cash provided by operating activities on the Statements of Cash Flows. See Note 18 for additional information regarding risk management activities and derivative transactions.

LOSS CONTINGENCIES AND ENVIRONMENTAL LIABILITIES

We accrue for loss contingencies, such as unfavorable results of litigation, when it is probable that a loss has been incurred and the amount of the loss can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, we record a loss contingency at the minimum amount in the range. With the exception of legal fees that are incremental direct costs of an environmental remediation effort, we do not accrue an estimate of legal fees when a contingent loss is initially recorded, but rather when the legal services are actually provided.

As discussed in Note 21, we accrue environmental remediation liabilities when the criteria for loss contingencies have been met. We record accruals for probable and estimable costs, including legal fees, related to environmental sites on an undiscounted basis. 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. Certain environmental expenses receive regulatory accounting treatment, under which the expenses are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable or on actual receipt of recovery. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

IMPAIRMENT OF LONG-LIVED ASSETS AND INVESTMENTS

We review the recoverability of long-lived tangible and intangible assets whenever impairment 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 impairment indicator exists for assets to be held and used, 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 or the asset group is to be disposed of, then an impairment loss is recognized for the difference between the carrying value and the fair value of the asset group.

We review our equity investments to evaluate whether or not a decline in fair value below the carrying value is an other-than-temporary decline. We consider 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 we determine that an other-than-temporary decline in value exists, the investments are written down to fair value with a new cost basis established.

2. MERGER AGREEMENT

On January 8, 2011, Duke Energy and Progress Energy entered into an Agreement and Plan of Merger (the Merger Agreement). Pursuant to the Merger Agreement, Progress Energy will be acquired by Duke Energy in a stock-for-stock transaction (the Merger) and become a wholly owned subsidiary of Duke Energy. The Merger Agreement originally had a termination date of January 8, 2012, which has been extended by the parties to July 8, 2012.

Under the terms of the Merger Agreement, each share of Progress Energy common stock will be canceled and converted into the right to receive 2.6125 shares of Duke Energy common stock. Each outstanding option to acquire, and each outstanding equity award relating to, one share of Progress Energy common stock will be converted into an option to acquire, or an equity award relating to, 2.6125 shares of Duke Energy common stock. The board of directors of Duke Energy approved a reverse stock split, at a ratio of 1-for-3, subject to completion of the Merger. Accordingly, the adjusted exchange ratio is expected to be 0.87083 of a share of Duke Energy common stock, options and equity awards for each Progress Energy common share, option and equity award.

The combined company, to be called Duke Energy, will have an 18-member board of directors. The board will be comprised of, subject to their ability and willingness to serve, all 11 current directors of Duke Energy and seven current directors of Progress Energy. At the time of the Merger, William D. Johnson, Chairman, President and CEO of Progress Energy, will be President and CEO of Duke Energy, and James E. Rogers, Chairman, President and CEO of Duke Energy, will be the Executive Chairman of the board of directors of Duke Energy, subject to their ability and willingness to serve.

Consummation of the Merger is subject to customary conditions, including, among others things, approval by the shareholders of each company, expiration or termination of the applicable Hart-Scott-Rodino Act waiting period, and receipt of approvals, to the extent required, from the FERC, the Federal Communications Commission, the NRC, the NCUC, the Kentucky Public Service Commission and the SCPSC. Although there are no merger-specific regulatory approvals required in Indiana, Ohio or Florida, the companies will continue to update the public service commissions in those states on the Merger, as applicable and as required. The status of these matters is as follows, and we cannot predict the outcome of pending approvals:

Shareholder Approval

- On August 23, 2011, the Merger was approved by the shareholders of Progress Energy and Duke Energy.

Federal Regulatory Approvals

- On March 28, 2011, Progress Energy and Duke Energy submitted their Hart-Scott-Rodino filing with the U.S. Department of Justice (DOJ) for review under U.S. antitrust laws. The 30-day waiting period required by the Hart-Scott-Rodino Act expired without Progress Energy or Duke Energy having received requests for additional information. Progress Energy and Duke Energy have met their obligations under the Hart-Scott-Rodino Act. However, the period in which Progress Energy and Duke Energy may close the Merger consistent with their Hart-Scott-Rodino obligations will expire on April 26, 2012. Because the Merger is not expected to close on or before April 26, 2012, Progress Energy and Duke Energy intend to make new filings under the Hart-Scott-Rodino Act in order to be able to close the Merger after such date and continue to meet their obligations under the Hart-Scott-Rodino Act.
- On January 5, 2012, the Federal Communications Commission extended its approval of the Assignment of Authorization

filings to transfer control of certain licenses. The extended approval expires on July 12, 2012.

- On September 30, 2011, the FERC, which assesses market power-related issues, conditionally approved the merger application filed by Progress Energy and Duke Energy. The approval is subject to the FERC's acceptance of market power mitigation measures to address the FERC's finding that the combined company could have an adverse effect on competition in the North Carolina and South Carolina wholesale power markets. Progress Energy and Duke Energy filed a market power mitigation plan with the FERC on October 17, 2011 that proposed a "virtual divestiture" under which power up to a certain amount would have been offered into the wholesale market rather than the sale or divestiture of physical assets. A virtual divestiture is one option the FERC indicated could be used to mitigate its market power concerns. On December 14, 2011, the FERC affirmed its conditional approval of the merger, but the FERC rejected the proposed market power mitigation plan. On February 22, 2012, Progress Energy and Duke Energy filed a notification with the NCUC of their intention to file a second market power mitigation plan with the FERC. The revised mitigation plan consists of two phases. Phase 1 is an interim mitigation that consists of a virtual divestiture whereby the companies propose a three-year plan to sell capacity and firm energy during the summer (June – August) and winter (December – February) to new market participants. Together, the companies would sell 800 MWs during summer off-peak hours, 475 MWs during summer peak hours, 225 MWs during winter off-peak hours, and 25 MWs during winter peak hours. The companies expect to secure contracts with potential buyers prior to filing the mitigation plan with the FERC. Phase 2 is a permanent mitigation that consists of constructing up to eight transmission projects in the combined service territories, which will expand the capability to import wholesale power into the Carolinas. The construction, preliminarily estimated to cost $75 million to $150 million, would begin after the Merger closes and take approximately three years to complete. The companies will be working with the North Carolina Public Staff and the South Carolina Office of Regulatory Staff (ORS) on appropriate state ratemaking treatment associated with the measures in the revised market mitigation plan and other merger-related issues. Final agreement to the proposed mitigation efforts will be subject to resolution of the state ratemaking issues. The NCUC has up to 30 days to review the revised mitigation plan before it is filed with the FERC.
- On April 4, 2011, Progress Energy and Duke Energy made two additional filings with the FERC. The first filing is a Joint Dispatch Agreement, pursuant to which PEC and Duke Energy Carolinas will agree to jointly dispatch their generation facilities in order to achieve certain of the operating efficiencies expected to result from the Merger. The second filing is a joint open access transmission tariff (OATT) pursuant to which PEC and Duke Energy Carolinas will agree to provide transmission service over their transmission facilities under a single transmission rate. On December 14, 2011, in conjunction with the aforementioned decision on the proposed market power mitigation plan, the FERC dismissed these related filings as not ripe for decision. As allowed under the FERC's December 14, 2011 order, Progress Energy and Duke Energy intend to refile the Joint Dispatch Agreement and OATT upon filing of the second market power mitigation plan with the FERC.
- On December 2, 2011, the NRC approved the filing requesting an indirect transfer of control of licenses for Progress Energy's nuclear facilities to include Duke Energy as the ultimate parent corporation on these licenses.

State Regulatory Approvals

- On April 4, 2011, Progress Energy and Duke Energy filed a merger approval application and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas with the NCUC. On September 2, 2011, the North Carolina Public Staff filed a settlement agreement with the NCUC. On September 6, 2011, Progress Energy and Duke Energy signed a settlement with the ORS, a party to the North Carolina proceedings to resolve the ORS's issues in the North Carolina proceeding. Under the settlement agreement with the North Carolina Public Staff, Progress Energy and Duke Energy will provide $650 million in system fuel cost savings for customers in North Carolina and South Carolina over the five years following the close of the Merger, maintain their current level of community support in North Carolina for the next four years, and provide $15 million for low-income energy assistance and workforce development in North Carolina. The settlement agreement also provides that direct merger-related expenses will not be recovered from customers; however, PEC may request recovery of costs incurred to create operational savings. The NCUC held hearings regarding the application on September 20-22, 2011. On November 23, 2011, Progress Energy and Duke Energy filed proposed orders and briefs with the NCUC. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.
- On April 25, 2011, Progress Energy and Duke Energy filed an application for approval of the merger of PEC and Duke Energy Carolinas and an application for approval of a Joint Dispatch Agreement between PEC and Duke Energy Carolinas

with the SCPSC. On September 13, 2011, Progress Energy and Duke Energy withdrew the application of the merger of PEC and Duke Energy Carolinas, as the merger of these entities is not likely to occur for several years after the close of the Merger. The SCPSC held hearings regarding the application for approval of the Joint Dispatch Agreement on December 12, 2011. During the hearing, PEC, Duke Energy Carolinas and the ORS agreed to terminate the settlement agreement, which resolved the ORS's issues in the NCUC merger proceeding, and replaced it with a commitment by PEC and Duke Energy Carolinas to provide PEC's and Duke Energy Carolinas' retail customers in South Carolina pro rata benefits equivalent to those approved by the NCUC in its order ruling upon PEC's and Duke Energy Carolinas' merger application. The docket will remain open pending the FERC's issuance of its final orders on the merger-related actions before the FERC.

- On October 28, 2011, the Kentucky Public Service Commission approved Progress Energy's and Duke Energy's merger-related settlement agreement with the Attorney General of the Commonwealth of Kentucky.

The Merger Agreement includes certain restrictions, limitations and prohibitions as to actions we may or may not take in the period prior to consummation of the Merger. Among other restrictions, the Merger Agreement limits our total capital spending, limits the extent to which we can obtain financing through long-term debt and equity, and we may not, without the prior approval of Duke Energy, increase our quarterly common stock dividend of $0.62 per share. In the fourth quarter of 2011, our board of directors declared a partial dividend payment to Progress Energy shareholders to align Progress Energy's dividend payment schedule with that of Duke Energy such that following the closing of the Merger, all stockholders of the combined company would receive dividends under the Duke Energy dividend schedule.

Certain substantial changes in ownership of Progress Energy, including the Merger, can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards (See Note 15).

The Merger Agreement contains certain termination rights for both companies; under specified circumstances we may be required to pay Duke Energy $400 million and Duke Energy may be required to pay us $675 million. In addition, under specified circumstances each party may be required to reimburse the other party for up to $30 million of merger-related expenses.

Certain Progress Energy shareholders filed class action lawsuits in the state and federal courts in North Carolina against Progress Energy and each of the members of Progress Energy's board of directors, which have been subsequently settled (See Note 22D).

In connection with the Merger, we established an employee retention plan for certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger and the employees' continued employment through a specified time period following the Merger. These payments will be recorded as compensation expense following consummation of the Merger. We estimate the costs of the retention plan to be $14 million.

In connection with the Merger, we announced plans to offer a voluntary severance plan (VSP) to certain eligible employees. Payments under the plan are contingent upon the consummation of the Merger. The window for eligible employees to request a voluntary end to their employment under the VSP opened on November 7, 2011, and ended on November 30, 2011. Approximately 650 employees requested and were approved for separation under the VSP in December 2011. The cost of the VSP is estimated to be between $90 million to $100 million, including $65 million to $70 million and $25 million to $30 million related to PEC and PEF, respectively. If the employee is not required to work for a significant period after the consummation of the Merger, the costs of any benefits paid under the VSP will be measured and recorded upon consummation of the Merger. If a significant retention period exists, the costs of benefits equal to what would be paid under our existing severance plan will be measured and recorded upon consummation of the Merger. Any additional benefits paid under the VSP will be recorded ratably over the remaining service periods of the affected employees.

In addition, we evaluated our business needs for office space after the Merger and formulated an exit plan to vacate one of our corporate headquarters buildings. Under the plan, we will gradually vacate the premises beginning in the fourth quarter of 2011 through January 1, 2013. In December 2011, we executed an agreement with a third party to sublease the building until 2035. The estimated exit cost liability associated with this exit plan is $17 million for us, of which $12 million of expense is attributable to PEC and $5 million to PEF. The exit cost liability will be recognized proportionately as we vacate the premises. During the fourth quarter of 2011, we recorded exit cost liabilities of $5 million for us, of which $3 million of expense is attributable to PEC and $2 million to

PEF. These costs are included in merger and integration-related costs.

In connection with the Merger, we incurred merger and integration-related costs of $46 million, net of tax, including $25 million, net of tax, and $21 million, net of tax, at PEC and PEF, respectively, for the year ended December 31, 2011. These costs are included in operations and maintenance (O&M) expense in our Consolidated Statements of Income.

3. NEW ACCOUNTING STANDARDS

FAIR VALUE MEASUREMENT AND DISCLOSURES

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2010-06, "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements," which amends Accounting Standards Codification (ASC) 820 to clarify certain existing disclosure requirements and to require a number of additional disclosures, including amounts and reasons for significant transfers between the three levels of the fair value hierarchy, and presentation of certain information in the reconciliation of recurring Level 3 measurements on a gross basis. ASU 2010-06 was effective for us on January 1, 2010, with certain disclosures effective January 1, 2011. The adoption of ASU 2010-06 resulted in additional disclosures in the notes to the financial statements but did not have an impact on our or the Utilities' financial position, results of operations or cash flows.

In May 2011, the FASB issued ASU 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs," which amends ASC 820 to develop a single, converged fair value framework between GAAP and International Financial Reporting Standards (IFRS). ASU 2011-04 is effective prospectively for us on January 1, 2012. The adoption of ASU 2011-04 will result in changes in certain fair value measurement principles, as well as additional disclosure in the notes to the financial statements. However, the impact of adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

GOODWILL IMPAIRMENT TESTING

In September 2011, the FASB issued ASU 2011-08, "Testing Goodwill for Impairment," which amends the guidance in ASC 350 on testing goodwill for impairment. Under the revised guidance, we have the option of performing a qualitative assessment before calculating the fair value of our reporting units. If it is determined in the qualitative assessment that it is more likely than not that the fair value of the reporting unit is less than its carrying amount, we would proceed to the two-step goodwill impairment test. Otherwise, no further impairment testing would be required. ASU 2011-08 is effective for us on January 1, 2012. The adoption of ASU 2011-08 is effective for both interim and annual goodwill tests and will give us the option to perform the qualitative assessment to determine the need for a two-step goodwill impairment test. The impact of the adoption is not expected to be significant to our or the Utilities' financial position, results of operations or cash flows.

DISCLOSURES ABOUT OFFSETTING ASSETS AND LIABILITIES

In December 2011, the FASB issued ASU 2011-11, "Disclosures About Offsetting Assets and Liabilities," which adds new disclosures to help financial statement users better understand the impact of offsetting arrangements on our balance sheet. The adoption of ASU 2011-11 will add disclosures showing both gross and net information about instruments and transactions eligible for offset in the balance sheet and instruments and transactions subject to an agreement similar to a master netting arrangement. ASU 2011-11 is effective for us on January 1, 2013, and will be retroactively applied.

4. DIVESTITURES

We have completed our business strategy of divesting nonregulated businesses to reduce our business risk and focus on core operations of the Utilities. Included in discontinued operations, net of tax are amounts related to adjustments of our prior sales of diversified businesses. These adjustments are generally due to guarantees and indemnifications provided for certain legal, tax and environmental matters. See Note 22C for further discussion of our guarantees. The ultimate resolution of these matters could result in additional adjustments in future periods. The information below presents the impacts of the divestitures on net income attributable to controlling interests.

A. TERMINALS OPERATIONS AND SYNTHETIC FUELS BUSINESSES

Prior to 2008, we had substantial operations associated with the production of coal-based solid synthetic fuels as defined under Section 29 (Section 29) of the Code and as redesignated effective 2006 as Section 45K of the Code (Section 45K and, collectively, Section 29/45K). The production and sale of these products qualified for federal income tax credits so long as certain requirements were satisfied. As a result of the expiration of the tax credit program, all of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007. During 2008, we also sold coal terminals and docks in West Virginia and Kentucky. The accompanying consolidated financial statements reflect the operations of our terminal operations and synthetic fuels businesses as discontinued operations.

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates. As a result, during the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations. See Note 22D for further discussion.

Results of coal terminals and docks and synthetic fuels businesses discontinued operations for the years ended December 31 were as follows:

(in millions)	2011	2010	2009
Loss before income taxes and noncontrolling interest	$ (8)	$ (11)	$ (125)
Income tax benefit, including tax credits	3	5	47
Loss from discontinued operations attributable to controlling interests	$ (5)	$ (6)	$ (78)

The total income tax benefit presented in the preceding table includes deferred income tax benefit (expense) of $28 million, $124 million and $(86) million for the years ended December 31, 2011, 2010 and 2009, respectively, related to synthetic fuels tax credits.

B. OTHER DIVERSIFIED BUSINESSES

Also included in discontinued operations are amounts related to adjustments of our prior sales of other diversified businesses. During the years ended December 31, 2011, 2010 and 2009, gains and losses related to post-closing adjustments and pre-divestiture contingencies of other diversified businesses were not material to our results of operations.

5. PROPERTY, PLANT AND EQUIPMENT

A. UTILITY PLANT

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

	Depreciable	Progress Energy		PEC		PEF	
(in millions)	Lives	**2011**	2010	**2011**	2010	**2011**	2010
Production plant	3-41	**$ 16,728**	$ 16,042	**$ 9,978**	$ 9,354	**$ 6,585**	$ 6,523
Transmission plant	7-75	**3,853**	3,530	**1,825**	1,626	**2,028**	1,904
Distribution plant	13-67	**9,053**	8,715	**4,887**	4,687	**4,166**	4,028
General plant and other	5-35	**1,431**	1,421	**749**	721	**682**	700
Utility plant in service		**$ 31,065**	$ 29,708	**$ 17,439**	$ 16,388	**$ 13,461**	$ 13,155

Generally, electric utility plant at PEC and PEF, other than nuclear fuel, is pledged as collateral for the first mortgage bonds of PEC and PEF, respectively (See Note 12). In the 2012 settlement agreement, PEF agreed to remove PEF's Crystal River Unit No. 3 Nuclear Plant (CR3) from rate base and will reclassify CR3 to a regulatory asset and suspend depreciation expense (See Note 8C).

As discussed in Note 8B, PEC intends to retire no later than December 31, 2013, all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 megawatts (MW) at four sites. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. At December 31, 2011, the $15 million net carrying value of this retired facility is included in regulatory assets on the Consolidated Balance Sheets.

AFUDC is charged to the cost of the plant for certain projects in accordance with the regulatory provisions for each jurisdiction. 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 PEC's electric utility plant was 8.7 percent in 2011 and 9.2 percent in 2010 and 2009. The composite AFUDC rate for PEF's electric utility plant was 7.4 percent, effective beginning April 1, 2010, based on its authorized return on equity (ROE) approved in the 2010 settlement agreement. This rate was unchanged by the 2012 settlement agreement (See Note 8C). Prior to April 1, 2010, the composite AFUDC rate for PEF's electric utility plant was 8.8 percent.

Our depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.3 percent, 2.0 percent and 2.4 percent in 2011, 2010 and 2009, respectively. The depreciation provisions related to utility plant and amortization of other utility plant, net were $675 million, $635 million and $626 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Notes 8 and 21).

PEC's depreciation provisions on utility plant and amortization of other utility plant, net, as a percent of average depreciable property other than nuclear fuel, were 2.1 percent for 2011, 2010 and 2009. The depreciation provisions related to utility plant and amortization of other utility plant, net were $360 million, $338 million and $328 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Note 8B).

PEF's depreciation provisions on utility plant, as a percent of average depreciable property other than nuclear fuel, were 2.4 percent in 2011, 1.9 percent in 2010 and 2.7 percent in 2009. The depreciation provisions related to utility plant were $315 million, $297 million and $299 million in 2011, 2010 and 2009, respectively. In addition to utility plant depreciation provisions, depreciation, amortization and accretion expense also includes decommissioning cost provisions, ARO accretion, cost of removal provisions (See Note 5C) and regulatory approved expenses (See Note 8C).

During 2010, PEF updated the depreciation rates approved by the FPSC in the 2009 base rate case. The rate change was effective January 1, 2010, and resulted in a decrease in depreciation expense of $43 million for 2010. Additionally, in December 2010, PEF filed the FPSC-approved depreciation rates with the FERC for use in its formula transmission rate for its OATT. The FERC filing requested depreciation rates be applied retroactively to January 1, 2010, whereby, if approved, the depreciation rate changes would result in a reduction to the depreciation expense charged to PEF's OATT customers, beginning June 1, 2011. The FERC on July 15, 2011, rejected the proposed adjustments to depreciation reserves.

Nuclear fuel, net of amortization at December 31, 2011 and 2010, was $767 million and $674 million, respectively, for Progress Energy; $540 million and $480 million, respectively, for PEC; and $227 million and $194 million, respectively, for PEF. The amount not yet in service at December 31, 2011 and 2010, was $575 million and $367 million, respectively, for Progress Energy; $322 million and $199 million, respectively, for PEC; and $253 million and $168 million, respectively, for PEF. Amortization of nuclear fuel costs, including disposal costs associated with obligations to the DOE and costs associated with obligations to the DOE for the decommissioning and decontamination of enrichment facilities, was $160 million, $132 million and $159 million for the years ended December 31, 2011, 2010 and 2009, respectively. This amortization expense is included in fuel used in electric generation in the Consolidated Statements of Income. PEC's amortization of nuclear fuel costs for the years ended December 31, 2011, 2010 and 2009 was $160 million, $132 million and $134 million, respectively. PEF's amortization of nuclear fuel costs for the year ended December 31, 2009, was $25 million. PEF did not have any amortization of nuclear fuel costs for the years ended December 31, 2011 and 2010, due to the CR3 outage (See Note 8C).

PEF's construction work in progress related to certain nuclear projects receives regulatory treatment. At December 31, 2011, PEF had $555 million of accelerated recovery of construction work in progress, of which $177 million was a component of a nuclear cost-recovery clause regulatory asset. At December 31, 2010, PEF had $519 million of accelerated recovery of construction work in progress, of which $237 million was a component of a nuclear cost-recovery clause regulatory asset. See Note 8C for further discussion of PEF's nuclear cost recovery.

B. JOINT OWNERSHIP OF GENERATING FACILITIES

PEC and PEF hold ownership interests in certain jointly owned generating facilities. Each is entitled to shares of the generating capability and output of each unit equal to their respective ownership interests. Each also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses, except in certain instances where agreements have been executed to limit certain joint owners' maximum exposure to the additional costs. Each of the Utilities' share of operating costs of the jointly owned generating facilities is included within the corresponding line in the Statements of Income. The co-owner of Intercession City Unit 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.

PEC's and PEF's ownership interests in the jointly owned generating facilities are listed below with related information at December

31:

(in millions) Subsidiary	Facility	Company Ownership Interest	Plant Investment	Accumulated Depreciation	Construction Work in Progress
2011					
PEC	**Mayo**	**83.83 %**	**$ 807**	**$ 296**	**$ 13**
PEC	**Harris**	**83.83 %**	**3,254**	**1,635**	**66**
PEC	**Brunswick**	**81.67 %**	**1,739**	**951**	**52**
PEC	**Roxboro Unit 4**	**87.06 %**	**733**	**470**	**12**
PEF	**Crystal River Unit 3**	**91.78 %**	**909**	**498**	**803**
PEF	**Intercession City Unit P11**	**66.67 %**	**23**	**12**	**-**
2010					
PEC	Mayo	83.83 %	$ 798	$ 294	$ 8
PEC	Harris	83.83 %	3,255	1,604	16
PEC	Brunswick	81.67 %	1,702	939	38
PEC	Roxboro Unit 4	87.06 %	706	457	22
PEF	Crystal River Unit 3	91.78 %	901	497	648
PEF	Intercession City Unit P11	66.67 %	23	11	-

In the tables above, plant investment and accumulated depreciation are not reduced by the regulatory disallowances related to the Shearon Harris Nuclear Plant (Harris), which are not applicable to the joint owner's ownership interest in Harris.

In the tables above, construction work in progress for CR3 is not reduced by the accelerated recovery of qualifying project costs under the FPSC nuclear cost-recovery rule (see Note 8C).

C. ASSET RETIREMENT OBLIGATIONS

At December 31, 2011 and 2010, our asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant, net of accumulated depreciation totaled $87 million and $90 million, respectively. PEC had immaterial asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant at December 31, 2011 and 2010. Primarily due to the impact of updated escalation factors in 2010, as discussed below, at December 31, 2011 and 2010, PEF had no asset retirement costs included in utility plant related to nuclear decommissioning of irradiated plant. At December 31, 2011 and 2010, additional PEF-related asset retirement costs, net of accumulated depreciation, of $87 million and $90 million, respectively, were recorded at Progress Energy as purchase accounting adjustments recognized when we purchased Florida Progress Corporation (Florida Progress) in 2000.

The fair value of funds set aside in the Utilities' nuclear decommissioning trust (NDT) funds for the nuclear decommissioning liability totaled $1.647 billion and $1.571 billion at December 31, 2011 and 2010, respectively (See Notes 13 and 14). The fair value of funds set aside in the NDT funds for the nuclear decommissioning liability totaled $1.088 billion and $1.017 billion at December 31, 2011 and 2010, respectively, for PEC and $559 million and $554 million, respectively, for PEF (See Notes 13 and 14). Net NDT unrealized gains are included in regulatory liabilities (See Note 8A).

Progress Energy's and PEC's nuclear decommissioning cost provisions, which are included in depreciation and amortization expense, were $31 million each in 2011, 2010 and 2009. As discussed below, PEF has suspended its accrual for nuclear decommissioning. Management believes that nuclear decommissioning costs that have been and will be recovered through rates by PEC and PEF will be sufficient to provide for the costs of decommissioning.

We recognized a benefit of $98 million in 2011 and expenses of $87 million and $141 million in 2010 and 2009, respectively, for the disposal or removal of utility assets that do not meet the definition of AROs, which are included in depreciation, amortization and accretion expense. PEC's related expenses were $125 million, $122 million and $106 million in 2011, 2010 and 2009, respectively. Due to a $250 million and $60 million cost of removal credit in 2011 and 2010, respectively, as allowed by the 2010 settlement agreement approved by the FPSC (See Note 8C), PEF recognized a benefit of $223 million and $35 million in 2011 and 2010, respectively. PEF's related expenses were $35 million in 2009.

The Utilities recognize removal, nonirradiated decommissioning and dismantlement of fossil generation plant costs in regulatory liabilities on the Consolidated Balance Sheets (See Note 8A). At December 31, such costs consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Removal costs	**$ 1,302**	$ 1,503	**$ 1,065**	$ 1,000	**$ 237**	$ 503
Nonirradiated decommissioning costs	**223**	233	**185**	172	**38**	61
Dismantlement costs	**125**	121	**-**	-	**125**	121
Non-ARO cost of removal	**$ 1,650**	$ 1,857	**$ 1,250**	$ 1,172	**$ 400**	$ 685

The NCUC requires that PEC update its cost estimate for nuclear decommissioning every five years. PEC received a new site-specific estimate of decommissioning costs for Robinson Nuclear Plant (Robinson) Unit No. 2, Brunswick Nuclear Plant (Brunswick) Units No. 1 and No. 2, and Harris, in December 2009, which was filed with the NCUC on March 16, 2010. PEC's estimate is based on prompt dismantlement decommissioning, which reflects the cost of removal of all radioactive and other structures currently at the site, with such removal occurring after operating license expiration. These decommissioning cost estimates also include interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). These estimates, in 2009 dollars, were $687 million for Unit No. 2 at Robinson, $591 million for Brunswick Unit No. 1, $585 million for Brunswick Unit No. 2 and $1.126 billion for Harris. The estimates are subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimates exclude the portion attributable to North Carolina Eastern Municipal Power Agency (Power Agency), which holds an undivided ownership interest in Brunswick and Harris. See Note 8D for information about the NRC operating licenses held by PEC.

The FPSC requires that PEF update its cost estimate for nuclear decommissioning every five years. PEF received a new site-specific estimate of decommissioning costs for CR3 in October 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. However, the FPSC deferred review of PEF's nuclear decommissioning study from the rate case to be addressed in 2010 in order for FPSC staff to assess PEF's study in combination with other utilities anticipated to submit nuclear decommissioning studies in 2010. PEF was not required to prepare a new site-specific nuclear decommissioning study in 2010; however, PEF was required to update the 2008 study with the most currently available escalation rates in 2010, which was filed with the FPSC in December 2010. We expect the FPSC to issue an order in 2012. PEF's estimate is based on prompt dismantlement decommissioning and includes interim spent fuel storage costs associated with maintaining spent nuclear fuel on site until such time that it can be transferred to a DOE facility (See Note 22D). The estimate, in 2008 dollars, is $751 million and is subject to change based on a variety of factors including, but not limited to, cost escalation, changes in technology applicable to nuclear decommissioning and changes in federal, state or local regulations. The cost estimate excludes the portion attributable to other co-owners of CR3. See Note 8D for information about the NRC operating license held by PEF for CR3. Based on the 2008 estimate, assumed operating license renewal and updated escalation factors in 2010, PEF decreased its asset retirement cost to zero and its ARO liability by approximately $37 million in 2010. Retail accruals on PEF's reserves for nuclear decommissioning were previously suspended under the terms of previous base rate settlement agreements. PEF expects to continue this suspension based on its 2010 nuclear decommissioning filing. No nuclear decommissioning reserve accrual is recorded at PEF following a FERC accounting order issued in November 2006.

The FPSC requires that PEF update its cost estimate for fossil plant dismantlement every four years. PEF received an updated fossil dismantlement study estimate in 2008, which PEF filed with the FPSC in 2009 as part of PEF's base rate filing. As a result of the base rate case, the FPSC approved an annual fossil dismantlement accrual of $4 million. PEF's reserve for fossil plant dismantlement was approximately $148 million and $144 million at December 31, 2011 and 2010, including amounts in the ARO liability for asbestos abatement, discussed below.

PEC and PEF have recognized ARO liabilities related to asbestos abatement costs. The ARO liabilities related to asbestos abatement costs were $23 million and $26 million at December 31, 2011 and 2010, respectively, at PEC and $29 million and $27 million at December 31, 2011 and 2010, respectively, at PEF.

Additionally, PEC and PEF have recognized ARO liabilities related to landfill capping costs. The ARO liabilities related to landfill capping costs were $6 million and $3 million at December 31, 2011 and 2010, respectively, at PEC and $7 million and $6 million at December 31, 2011 and 2010, respectively, at PEF.

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

The following table presents the changes to the AROs during the years ended December 31. Revisions to prior estimates of the PEC and PEF regulated ARO are primarily related to the updated cost estimates for nuclear decommissioning and asbestos described above.

(in millions)	Progress Energy	PEC	PEF
Asset retirement obligations at January 1, 2010	$ 1,170	$ 801	$ 369
Additions	4	4	-
Accretion expense	65	46	19
Revisions to prior estimates	(39)	(2)	(37)
Asset retirement obligations at December 31, 2010	1,200	849	351
Accretion expense	**67**	**49**	**18**
Revisions to prior estimates	**(2)**	**(2)**	**-**
Asset retirement obligations at December 31, 2011	**$ 1,265**	**$ 896**	**$ 369**

D. INSURANCE

The Utilities are members 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, each company is insured for $500 million at each of its respective nuclear plants. In addition to primary coverage, NEIL also provides decontamination, premature decommissioning and excess property insurance with limits of $1.750 billion on each nuclear plant.

Insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages at nuclear generating units is also provided through membership in NEIL. Both PEC and PEF are insured under this program, following a 12-week deductible period, for 52 weeks in the amounts ranging from $3.5 million to $4.5 million per week. Additional weeks of coverage ranging from 71 weeks to 110 weeks are provided at 80 percent of the above weekly amounts. For the current policy period, the companies are subject to retrospective premium assessments of up to approximately $29 million with respect to the primary coverage, $40 million with respect to the decontamination, decommissioning and excess property coverage, and $25 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 NRC, each company'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 the plant, before any proceeds can be used for decommissioning, plant repair or restoration. Each company is responsible to the extent losses may exceed limits of the coverage described above. At December 31, 2011, PEF has an outstanding claim with NEIL for CR3

(See Notes 6 and 8C).

Both of the Utilities are insured against public liability for a nuclear incident up to $12.595 billion per occurrence. Under the current provisions of the Price Anderson Act, which limits liability for accidents at nuclear power plants, each company, as an owner of nuclear units, 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 each insured nuclear incident exceed the primary level of coverage provided by American Nuclear Insurers, each company would be subject to pro rata assessments of up to $117.5 million for each reactor owned for each incident. Payment of such assessments would be made over time as necessary to limit the payment in any one year to no more than $17.5 million per reactor owned per incident. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before August 29, 2013.

Under the NEIL policies, if there were multiple terrorism losses within one year, NEIL would make available one industry aggregate limit of $3.240 billion for noncertified acts, 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.

The Utilities self-insure their transmission and distribution lines against loss due to storm damage and other natural disasters. PEF maintains a storm damage reserve and has a regulatory mechanism to recover the costs of named storms on an expedited basis (See Note 8C).

For loss or damage to non-nuclear properties, excluding self-insured transmission and distribution lines, the Utilities are insured under an all-risk property insurance program with a total limit of $600 million per loss. The basic deductible is $2.5 million per loss, and there is no outage or replacement power coverage under this program.

6. RECEIVABLES

Income taxes receivable and interest income receivables are not included in receivables. These amounts are included in prepayments and other current assets or shown separately on the Consolidated Balance Sheets. At December 31 receivables were comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Trade accounts receivable	**$ 520**	$ 651	**$ 276**	$ 346	**$ 244**	$ 303
Unbilled accounts receivable	**157**	223	**102**	136	**55**	87
Other receivables	**168**	75	**123**	47	**20**	12
NEIL receivable (Note 8C)	**71**	119	**-**	-	**71**	119
Allowance for doubtful receivables	**(27)**	(35)	**(9)**	(10)	**(18)**	(25)
Total receivables, net	**$ 889**	$ 1,033	**$ 492**	$ 519	**$ 372**	$ 496

Other receivables for Progress Energy and PEC above include $92 million at December 31, 2011, related to the award from the DOE for asserted damages associated with spent nuclear fuel (See Note 22D).

7. INVENTORY

At December 31 inventory was comprised of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Fuel for production	**$ 681**	$ 542	**$ 323**	$ 192	**$ 358**	$ 350
Materials and supplies	**747**	676	**446**	395	**301**	281
Emission allowances	**4**	8	**1**	3	**3**	5
Other	**6**	-	**5**	-	**1**	-
Total inventory	**$ 1,438**	$ 1,226	**$ 775**	$ 590	**$ 663**	$ 636

Emission allowances above exclude long-term emission allowances included in other assets and deferred debits on the Consolidated Balance Sheets for Progress Energy, PEC and PEF of $28 million, $4 million and $24 million, respectively, at December 31, 2011. Long-term emission allowances for Progress Energy, PEC and PEF were $33 million, $5 million and $28 million, respectively, at December 31, 2010.

8. REGULATORY MATTERS

On January 8, 2011, Progress Energy and Duke Energy entered into the Merger Agreement. See Note 2 for regulatory information related to the Merger with Duke Energy.

A. REGULATORY ASSETS AND LIABILITIES

As regulated entities, the Utilities are subject to the provisions of GAAP for regulated operations. Accordingly, the Utilities record certain assets and liabilities resulting from the effects of the ratemaking process that would not be recorded under GAAP for nonregulated entities. Regulatory assets may be recorded for certain employee benefit costs of unregulated affiliates that will be allocated to the Utilities and recovered through rates of the Utilities. Our and the Utilities' ability to continue to meet the criteria for application of GAAP for regulated operations could be affected in the future by competitive forces and restructuring in the electric utility industry. In the event that GAAP for regulated operations no longer applies to a separable portion of our operations, related regulatory assets and liabilities would be eliminated unless an appropriate regulatory recovery mechanism was provided. Additionally, such an event would require the Utilities to determine if any impairment to other assets, including utility plant, exists and write down impaired assets to their fair values.

Except for portions of deferred fuel costs and loss on reacquired debt, all regulatory 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. We expect to fully recover our regulatory assets and refund our regulatory liabilities through customer rates under current regulatory practice.

At December 31 the balances of regulatory assets (liabilities) were as follows:

PROGRESS ENERGY

(in millions)	2011	2010
Deferred fuel costs – current (Notes 8B and 8C)	$ 275	$ 169
Nuclear deferral (Note 8C)	-	7
Total current regulatory assets	275	176
Nuclear deferral (Note 8C)[a]	117	178
Deferred impact of ARO (Note 5C)[b]	137	122
Income taxes recoverable through future rates[c]	352	302
Loss on reacquired debt[d]	29	31
Postretirement benefits (Note 17)[e]	1,506	1,105
Derivative mark-to-market adjustment (Note 18A)[f]	708	505
DSM/Energy-efficiency deferral (Note 8B)[g]	92	57
Other	84	74
Total long-term regulatory assets	3,025	2,374
Environmental (Note 8C)	(7)	(45)
Energy conservation (Note 8C)	(19)	(11)
Nuclear deferral (Note 8C)	(15)	-
Other current regulatory liabilities	(7)	(3)
Total current regulatory liabilities	(48)	(59)
Amount to be refunded to customers (Note 8C)[h]	(288)	-
Non-ARO cost of removal (Note 5C)[b]	(1,650)	(1,857)
Deferred impact of ARO (Note 5C)[b]	(146)	(143)
Net nuclear decommissioning trust unrealized gains (Note 5C)[i]	(412)	(421)
Storm reserve (Note 8C)[j]	(132)	(136)
Other	(72)	(78)
Total long-term regulatory liabilities	(2,700)	(2,635)
Net regulatory assets (liabilities)	$ 552	$ (144)

PEC

(in millions)	2011	2010

Deferred fuel costs – current (Note 8B)	**$**	**31**	$	71
Deferred impact of ARO (Note 5C)(b)		**124**		112
Income taxes recoverable through future rates(c)		**140**		103
Loss on reacquired debt(d)		**12**		13
Postretirement benefits (Note 17)(e)		**691**		545
Derivative mark-to-market adjustment (Note 18A)(f)		**200**		121
DSM/Energy-efficiency deferral (Note 8B)(g)		**92**		57
Other		**51**		36
Total long-term regulatory assets		**1,310**		987
Deferred fuel costs – current (Note 8B)		**(2)**		-
Non-ARO cost of removal (Note 5C)(b)		**(1,250)**		(1,172)
Net nuclear decommissioning trust unrealized gains (Note 5C)(i)		**(266)**		(267)
Other		**(27)**		(22)
Total long-term regulatory liabilities		**(1,543)**		(1,461)
Net regulatory liabilities	**$**	**(204)**	$	(403)

PEF

(in millions)		**2011**		2010
Deferred fuel costs – current (Note 8C)	**$**	**244**	$	98
Nuclear deferral (Note 8C)		**-**		7

Total current regulatory assets	**244**	105
Nuclear deferral (Note 8C)[(a)]	**117**	178
Income taxes recoverable through future rates[(c)]	**212**	199
Loss on reacquired debt[(d)]	**17**	18
Postretirement benefits (Note 17)[(e)]	**702**	560
Derivative mark-to-market adjustment (Note 18A)[(f)]	**508**	384
Other	**46**	48
Total long-term regulatory assets	**1,602**	1,387
Environmental (Note 8C)	**(7)**	(45)
Energy conservation (Note 8C)	**(19)**	(11)
Nuclear deferral (Note 8C)	**(15)**	-
Other current regulatory liabilities	**(5)**	(3)
Total current regulatory liabilities	**(46)**	(59)
Amount to be refunded to customers (Note 8C)[(h)]	**(288)**	-
Non-ARO cost of removal (Note 5C)[(b)]	**(400)**	(685)
Deferred impact of ARO (Note 5C)[(b)]	**(45)**	(47)
Net nuclear decommissioning trust unrealized gains (Note 5C)[(i)]	**(146)**	(154)
Storm reserve (Note 8C)[(j)]	**(132)**	(136)
Other	**(60)**	(62)
Total long-term regulatory liabilities	**(1,071)**	(1,084)
Net regulatory assets	**$ 729**	$ 349

The recovery and amortization periods for these regulatory assets and (liabilities) at December 31, 2011, are as follows:

(a) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding five years.

(b) Asset retirement and removal liabilities are recorded over the related property lives, which may range up to 65 years, and will be settled and adjusted following completion of the related activities.

(c) Income taxes recoverable through future rates are recovered over the related property lives, which may range up to 65 years.

(d) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 30 years.

(e) Recovered and amortized over the remaining service period of employees. In accordance with a 2009 FPSC order, PEF's 2009 deferred pension expense of $34 million will be amortized to the extent that annual pension expense is less than the $27 million allowance provided for in base rates (See Note 17).

(f) Related to derivative unrealized gains and losses that are recorded as a regulatory liability or asset, respectively, until the contracts are settled. After contract settlement and consumption of the related fuel, the realized gains or losses are passed through the fuel cost-recovery clause.

(g) Recorded and recovered or amortized as approved by the appropriate state utility commission over a period not exceeding 10 years.

(h) Recorded as a result of the 2012 settlement agreement to be refunded to customers through the fuel clause over four years beginning in 2013 (see Note 8C).

(i) Related to unrealized gains and losses on NDT funds that are recorded as a regulatory asset or liability, respectively, until the funds are used to decommission a nuclear plant.

(j) Utilized as storm restoration expenses are incurred.

B. PEC RETAIL RATE MATTERS

BASE RATES

PEC's base rates are subject to the regulatory jurisdiction of the NCUC and SCPSC. In PEC's most recent base rate cases in 1988, the NCUC and the SCPSC each authorized a ROE of 12.75 percent.

COST RECOVERY FILINGS

On November 14, 2011, the NCUC approved PEC's settlement agreement for an $85 million increase in the fuel rate charged to its North Carolina retail ratepayers, driven by rising fuel prices. The settlement agreement updated certain costs from PEC's original filing and included the impact of a $24 million disallowance of replacement power costs resulting from prior-year performance of PEC's nuclear plants. The increase was effective December 1, 2011, and increased residential electric bills by $2.75 per 1,000 kilowatt-hours (kWh) for fuel cost recovery. Also on November 14, 2011, the NCUC approved PEC's request for a $24 million increase in the demand-side management (DSM) and EE rate charged to its North Carolina ratepayers. The increase was effective December 1, 2011, and increased the residential electric bills by $1.08 per 1,000 kWh for DSM and EE cost recovery. On November 10, 2011, the NCUC approved PEC's request for a $9 million increase for North Carolina Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS). The increase was effective December 1, 2011, and decreased the residential electric bills by $0.02 per 1,000 kWh. The residential NC REPS rate decreased while the total amount to be recovered increased due to the allocation of the NC REPS recovery between customer classes. The net impact of the settlement agreement and filings results in an average increase in residential electric bills of 3.7 percent. At December 31, 2011, PEC's North Carolina deferred fuel and DSM/EE balances were $31 million and $78 million, respectively.

On June 29, 2011, the SCPSC approved a $22 million increase in the fuel rate charged to its South Carolina ratepayers, driven by rising fuel prices. The increase was effective July 1, 2011, and increased residential electric bills by $3.45 per 1,000 kWh. Also on June 29, 2011, the SCPSC approved a $4 million increase in the DSM and EE rate. The increase was effective July 1, 2011, and increased residential electric bills by $1.25 per 1,000 kWh. The net impact of the two filings resulted in an average increase in residential electric bills of 4.7 percent. At December 31, 2011, PEC's South Carolina deferred fuel and DSM/EE balances were $(2) million and $14 million, respectively.

OTHER MATTERS

Construction of Generating Facilities

On June 1, 2011, a newly constructed 600-MW combined cycle natural gas-fueled unit at the Smith Energy Complex was placed in service.

On October 22, 2009, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 950-MW combined cycle natural gas-fueled electric generating facility at a site in Wayne County, N.C. PEC projects that the generating facility will be in service by January 2013.

On June 9, 2010, the NCUC issued its order granting PEC a Certificate of Public Convenience and Necessity to construct an approximately 620-MW combined cycle natural gas-fueled electric generating facility at a site in New Hanover County, N.C., to replace the existing coal-fired generation at this site. PEC projects that the generating facility will be in service in December 2013.

Planned Retirements of Generating Facilities

PEC filed a plan with the NCUC and the SCPSC to retire all of its coal-fired generating facilities in North Carolina that do not have scrubbers. These facilities total approximately 1,500 MW at four sites. On October 1, 2011, PEC retired the Weatherspoon coal-fired generating units. PEC expects to retire the remaining coal-fired facilities by the end of 2013.

The net carrying value of the three remaining facilities at December 31, 2011, of $163 million is included in other utility plant, net on the Consolidated Balance Sheets. Consistent with ratemaking treatment, PEC will continue to depreciate each plant using the current depreciation lives and rates on file with the NCUC and the SCPSC until the earlier of the plant's retirement or PEC's completion and filing of a new depreciation study on or before March 31, 2013. The net carrying value of the retired facility at December 31, 2011, of $15 million is included in regulatory assets on the Consolidated Balance Sheets. PEC expects to include the four facilities' remaining net carrying value in rate base after retirement. The final recovery periods may change in connection with the regulators' determination of the recovery of the remaining net carrying value.

C. PEF RETAIL RATE MATTERS

CR3 OUTAGE

In September 2009, CR3 began an outage for normal refueling and maintenance as well as an uprate project to increase its generating capability and to replace two steam generators. During preparations to replace the steam generators, workers discovered a delamination (or separation) within the concrete at the periphery of the containment building, which resulted in an extension of the outage. After analysis, PEF determined that the concrete delamination at CR3 was caused by redistribution of stresses in the containment wall that occurred when PEF created an opening to accommodate the replacement of the unit's steam generators. In March 2011, the work to return the plant to service was suspended after monitoring equipment at the repair site identified a new delamination that occurred in a different section of the outer wall after the repair work was completed and during the late stages of retensioning the containment building. CR3 has remained out of service while PEF conducted an engineering analysis and review of the new delamination and evaluated repair options. Subsequent to March 2011, monitoring equipment has detected additional changes and further damage in the partially tensioned containment building and additional cracking or delaminations could occur during the repair process.

PEF analyzed multiple repair options as well as early decommissioning and believes, based on the information and analyses conducted to date, that repairing the unit is the best option. PEF engaged outside engineering consultants to perform the analysis of possible repair options for the containment building. The consultants analyzed 22 potential repair options and ultimately narrowed those to four. PEF, along with other independent consultants, reviewed the four options for technical issues, constructability, and licensing feasibility as well as cost.

Based on that initial analysis, PEF selected the best repair option, which would entail systematically removing and replacing concrete in substantial portions of the containment structure walls. The planned option does not include the area where concrete was replaced during the initial repair. The preliminary cost estimate for this repair as filed with the FPSC on June 27, 2011, is between $900 million and $1.3 billion. Engineering design of the repair is under way. PEF will update the current estimate as this work is completed.

PEF is moving forward systematically and will perform additional detailed engineering analyses and designs, which could affect any repair plan. This process will lead to more certainty for the cost and schedule of the repair. PEF will continue to refine and assess the plan, and the prudence of continuing to pursue it, based on new developments and analyses as the process moves forward. Under this repair plan, PEF estimates that CR3 will return to service in 2014. The decision related to repairing or decommissioning CR3 is complex and subject to a number of unknown factors, including but not limited to, the cost of repair and the likelihood of obtaining NRC approval to restart CR3 after repair. A number of factors could affect the repair plan, the return-to-service date and costs, including regulatory reviews, final engineering designs, contract negotiations, the ultimate work scope completion, testing, weather, the impact of new information discovered during additional testing and analysis and other developments.

PEF maintains insurance for property damage and incremental costs of replacement power resulting from prolonged accidental outages through NEIL as discussed in Note 5D. NEIL has confirmed that the CR3 initial delamination is a covered accident but has not yet made a determination as to coverage for the second delamination. Following a 12-week deductible period, the NEIL program provided reimbursement for replacement power costs for 52 weeks at $4.5 million per week, through April 9, 2011. An additional 71 weeks of coverage, which runs through August 2012, is provided at $3.6 million per week. Accordingly, the NEIL program provides replacement power coverage of up to $490 million per event. Actual replacement power costs have exceeded the insurance coverage through December 31, 2011. PEF anticipates that future replacement power costs will continue to exceed the insurance coverage. PEF also maintains insurance coverage through NEIL's accidental property damage program, which provides insurance coverage up to $2.25 billion with a $10 million deductible per claim.

PEF is continuing to work with NEIL for recovery of applicable repair costs and associated replacement power costs. PEF has not yet received a definitive determination from NEIL about the insurance coverage related to the second delamination. In addition, no replacement power reimbursements were received from NEIL in the second half of 2011. These considerations led us to conclude that at December 31, 2011, it was not probable that NEIL will voluntarily pay the full coverage amounts we believe they owe under the applicable insurance policies. Given the circumstances, accounting standards require full recovery to be probable to recognize an insurance receivable. Therefore, PEF has suspended recording any further insurance receivables from NEIL related to the second delamination and removed the associated $222 million NEIL receivable. PEF recorded a corresponding $154 million addition to its deferred fuel regulatory asset and a $68 million addition to construction work in progress. Negotiations continue with NEIL regarding coverage associated with the second delamination, and PEF continues to believe that all applicable costs associated with bringing CR3 back into service are covered under all insurance policies.

The following table summarizes the CR3 replacement power and repair costs and recovery through December 31, 2011:

(in millions)	Replacement power costs	Repair costs
Spent to date	$ 478	$ 258
NEIL proceeds received	(162)	(136)
Insurance receivable at December 31, 2011, net	(55)	(3)
Balance for recovery[(a)]	$ 261	$ 119

(a) See "2012 Settlement Agreement" and "Fuel Cost Recovery" below for discussion of PEF's ability to recover prudently incurred fuel and purchase power costs and CR3 repair costs.

PEF believes the actions taken and costs incurred in response to the CR3 delamination have been prudent and, accordingly, considers replacement power and capital costs not recoverable through insurance to be recoverable through its fuel cost-recovery clause or base rates. Additional replacement power costs and repair and maintenance costs incurred until CR3 is returned to service could be material. Additionally, we cannot be assured that CR3 can be repaired and brought back to service until full engineering and other analyses are completed.

On October 25, 2010, the FPSC approved PEF's motion to establish a separate spin-off docket to review the prudence and costs related to the outage and replacement fuel and power costs associated with the CR3 extended outage. The FPSC subsequently issued an order dividing the docket into three phases. The first phase will include a prudence review of the events and decisions of PEF leading up to the first delamination event. The second phase will be a consideration of the prudence of PEF's decision to repair or decommission CR3. The third phase of this docket will include the decisions and events subsequent to the first delamination leading up to the March 14, 2011 delamination event and the subsequent repair of the containment building. See "2012 Settlement Agreement – CR3" below for a discussion of the resolution of this docket.

2012 SETTLEMENT AGREEMENT

On February 22, 2012, the FPSC approved a comprehensive settlement agreement between PEF, the Florida Office of Public Counsel and other consumer advocates. The 2012 settlement agreement will continue through the last billing cycle of December 2016. The agreement addresses three principal matters: PEF's proposed Levy Nuclear Power Plant (Levy) Nuclear Project cost recovery, the CR3 delamination prudence review pending before the FPSC, and certain base rate issues. When all of the settlement provisions are factored in, the total increase in 2013 for residential customer bills will be approximately $4.93 per 1,000 kWh, or 4 percent.

Levy

Under the terms of the 2012 settlement agreement, PEF will set the residential cost-recovery factor of PEF's proposed two units at Levy (see "Nuclear Cost Recovery – Levy Nuclear") at $3.45 per 1,000 kWh effective in the first billing cycle of January 2013 and continuing for a five-year period. This amount is intended to recover the estimated retail project costs to date plus costs necessary to obtain the combined license (COL) and any engineering, procurement and construction (EPC) cancellation costs, if PEF ultimately chooses to cancel that contract. PEF will not recover any additional Levy costs from customers through the term of the agreement, or file for any additional recovery before March 1, 2017, unless otherwise agreed to by the parties to the agreement. In addition, the consumer parties will not oppose PEF continuing to pursue a COL for Levy. After the five-year period, PEF will true up any actual costs not recovered under the Levy cost-recovery factor.

The 2012 settlement agreement also provides that PEF will treat the allocated wholesale cost of Levy as a retail regulatory asset and include this asset as a component of rate base and amortization expense for regulatory reporting. PEF will have the discretion to suspend such amortization in full or in part provided that PEF amortizes all of the regulatory asset by December 31, 2016.

CR3

Under the terms of the 2012 settlement agreement, PEF will be permitted to recover prudently incurred fuel and purchased power costs through the fuel clause without regard for the absence of CR3 for the period from the beginning of the CR3 outage through the earlier of the term of the agreement or the return of CR3 to commercial service. If PEF does not begin repairs of CR3 prior to the end of 2012, PEF will refund replacement power costs on a pro rata basis based on the in-service date of up to $40 million in 2015 and $60 million in 2016. The parties to the agreement waive their right to challenge PEF's recovery of these costs. The parties to the agreement maintain the right to challenge the prudence and reasonableness of PEF's fuel acquisition and power purchases, and other fuel prudence issues unrelated to the CR3 outage. All prudence issues from the steam generator project inception through the date of settlement approval by the FPSC are resolved.

To the extent that PEF pursues the repair of CR3, PEF will establish an estimated cost and repair schedule with ongoing consultation with the parties to the agreement. The established cost, to be approved by our board of directors, will be the basis for project measurement. If costs exceed the board-approved estimate, overruns will be split evenly between our shareholders and PEF customers up to $400 million. The parties to the agreement agree to meet to discuss the method of recovery of any overruns in excess of $400 million, with final decision by the FPSC if resolution cannot be reached. If the repairs begin prior to the end of 2012, the parties to the agreement waive their rights to challenge PEF's decision to repair and the repair plan chosen by PEF. In addition, there will be limited rights to challenge recovery of the repair execution costs incurred prior to the final resolution on NEIL coverage. The parties to the agreement will discuss the treatment of any potential gap between NEIL repair coverage and the estimated cost, with final decision by the FPSC if resolution cannot be reached. If the repairs do not begin prior to the end of 2012, the parties to the agreement reserve the right to challenge the prudence of PEF's repair decision, plan and implementation.

PEF also retains sole discretion and flexibility to retire the unit without challenge from the parties to the agreement. If PEF decides to retire CR3, PEF is allowed to recover all remaining CR3 investments and to earn a return on the CR3 investments set at its current authorized overall cost of capital, adjusted to reflect a ROE set at 70 percent of the current FPSC-authorized ROE, no earlier than the first billing cycle of January 2017. Additionally, any NEIL proceeds received after the settlement will be applied first to replacement power costs incurred after December 31, 2012, with the remainder used to write down the remaining CR3 investments.

Base Rates, Customer Refund and Other Terms

Under the terms of the 2012 settlement agreement, PEF will maintain base rates at the current levels through the last billing cycle of December 2016, except as described as follows. The agreement provides for a $150 million annual increase in revenue requirements effective with the first billing cycle of January 2013, while maintaining the current ROE range of 9.5 percent to 11.5 percent. PEF will suspend depreciation expense and reverse certain regulatory liabilities associated with CR3 effective on the implementation date of the agreement. Additionally, rate base associated with CR3 investments will be removed from retail rate base effective with the first billing cycle of January 2013. PEF will accrue, for future rate-setting purposes a carrying charge at a rate of 7.4 percent on the CR3 investment until CR3 is returned to service and placed back into retail rate base. Upon return of CR3 to commercial service, PEF will be authorized to increase its base rates for the annual revenue requirements of all CR3 investments. The parties to the agreement reserve the right to participate in any hearings challenging the appropriateness of PEF's CR3 revenue requirements. In the month following CR3's return to commercial service, PEF's ROE range will increase to 9.7 percent to 11.7 percent. If PEF's retail base rate earnings fall below the ROE range, as reported on a FPSC-adjusted or pro-forma basis on a PEF monthly earnings surveillance report, PEF may petition the FPSC to amend its base rates during the term of the agreement.

Under the terms of the 2012 settlement agreement, PEF will refund $288 million as of December 31, 2011, to customers through the fuel clause. PEF will refund $129 million in each of 2013 and 2014, and an additional $10 million annually to residential and small commercial customers in 2014, 2015 and 2016. At December 31, 2011, a regulatory liability was established for the $288 million to be refunded in future periods. The corresponding charge was recorded as a reduction of 2011 revenues.

The cost of pollution control equipment that PEF installed and has in-service at CR4 and CR5 to comply with the Federal Clean Air Interstate Rule (CAIR) is currently recovered under the Environmental Cost Recovery Clause (ECRC). The 2012 settlement agreement provides for PEF to remove those assets from recovery in the ECRC and transfer those assets to base rates effective with the first billing cycle of January 2014. The related base rate increase will be in addition to the $150 million base rate increase effective January 2013. O&M expenses associated with those assets will not be included in the base rates and will continue to be recovered through the ECRC.

The 2012 settlement agreement provides for PEF to continue to recover carrying costs and other nuclear cost recovery clause-recoverable items related to the CR3 uprate project, but PEF will not seek an in-service recovery until nine months following CR3's return to commercial service. Carrying costs will be recovered through the nuclear cost recovery clause until base rates have been increased for these assets.

The 2012 settlement agreement also allows PEF to continue to reduce amortization expense (cost of removal component) beyond the expiration of the 2010 settlement agreement through the term of the 2012 settlement agreement. This reduction is limited by the eligible remaining balance of the cost of removal reserve ($246 million at December 31, 2011). Additionally, the 2012 settlement agreement extends PEF's ability to expedite recovery of the cost of named storms and to maintain a storm reserve at its level as of the implementation date of the agreement, and removed the maximum allowed monthly surcharge established by the 2010 settlement agreement.

2010 SETTLEMENT AGREEMENT

On June 1, 2010, the FPSC approved a settlement agreement between PEF and the interveners, with the exception of the Florida Association for Fairness in Ratemaking, to the 2009 rate case. As part of the settlement, PEF withdrew its motion for reconsideration of the rate case order. Among other provisions, under the terms of the settlement agreement, PEF will maintain base rates at current levels through the last billing cycle of 2012. The settlement agreement also provides that PEF will have the discretion to reduce amortization expense (cost of removal component) by up to $150 million in 2010, up to $250 million in 2011, and up to any remaining balance in the cost of removal reserve in 2012 until the earlier of (a) PEF's applicable cost of removal reserve reaches zero, or (b) the expiration of the settlement agreement at the end of 2012. In the event PEF reduces amortization expense by less than the annual amounts for 2010 or 2011, PEF may carry forward (i.e., increase the annual cap by) any unused cost of removal reserve amounts in subsequent years during the term of the agreement. The balance of the cost of removal reserve is impacted by accruals in accordance with PEF's latest depreciation study, removal costs expended and reductions in amortization expense as permitted by the settlement agreement. For the year ended December 31, 2011, PEF recognized a $250 million reduction in amortization expense pursuant to the settlement agreement. PEF had eligible cost of removal reserves of $246 million remaining at December 31, 2011. The settlement agreement also provides PEF with the opportunity to earn a ROE of up to 11.5 percent and provides that if PEF's actual retail base rate earnings fall below a 9.5 percent ROE on an adjusted or pro-forma basis, as reported on a historical 12-month basis during the term of the agreement, PEF may seek general, limited or interim base rate relief, or any combination thereof. Prior to requesting any such relief, PEF must have reflected on its referenced surveillance report associated amortization expense reductions of at least $150 million. The settlement agreement does not preclude PEF from requesting the FPSC to approve the recovery of costs (a) that are of a type which traditionally and historically would be, have been or are presently recovered through cost-recovery clauses or surcharges; or (b) that are incremental costs not currently recovered in base rates, which the legislature or FPSC determines are clause recoverable; or (c) which are recoverable through base rates under the nuclear cost-recovery legislation or the FPSC's nuclear cost-recovery rule. PEF also may, at its discretion, accelerate in whole or in part the amortization of certain regulatory assets over the term of the settlement agreement. Finally, PEF will be allowed to recover the costs of named storms on an expedited basis after depletion of the storm damage reserve. Specifically, 60 days following the filing of a cost-recovery petition with the FPSC and based on a 12-month recovery period, PEF can begin recovery, subject to refund, through a surcharge of up to $4.00 per 1,000 kWh on monthly residential customer bills for storm costs. In the event the storm costs exceed that level, any excess additional costs will be deferred and recovered in a subsequent year or years as determined by the FPSC. Additionally, the order approving the settlement agreement allows PEF to use the surcharge to replenish the storm damage reserve to $136 million, the level as of June 1, 2010, after storm costs are fully recovered. At December 31, 2011, PEF's storm damage reserve was $132 million.

On September 14, 2010, the FPSC approved a reduction to PEF's AFUDC rate, from 8.8 percent to 7.4 percent. This new rate is based on PEF's updated authorized ROE and all adjustments approved on January 11, 2010, in PEF's base rate case and will be used for all purposes except for nuclear recoveries with original need petitions submitted on or before December 31, 2010, as permitted by FPSC regulations.

FUEL COST RECOVERY

On November 22, 2011, the FPSC approved an increase of the total fuel-cost recovery by $162 million, increasing the residential rate by $3.32 per 1,000 kWh, or 2.78 percent, effective January 1, 2012. This increase is due to an increase of $3.99 per 1,000 kWh for the projected recovery of fuel costs offset by a decrease of $0.67 per 1,000 kWh for the projected recovery through the Capacity Cost-Recovery Clause (CCRC). The increase in the projected recovery of fuel costs is due to an under-recovery from the prior year. The decrease in the CCRC is primarily due to lower anticipated costs associated with Levy, and the deferral of 2011 and 2012 estimated costs associated with PEF's CR3 uprate project until 2012 (see "Nuclear Cost Recovery"), partially offset by increased capacity costs and a reduction of the refund related to an over-recovery from the prior year. Within the fuel clause, PEF received approval to collect, subject to refund, replacement power costs related to the CR3 nuclear plant outage (See "CR3 Outage" and "2012 Settlement Agreement").

At December 31, 2011, PEF's deferred fuel regulatory liability was $44 million comprised of a $244 million current regulatory asset and a $288 million noncurrent regulatory liability (See "2012 Settlement Agreement"). The current regulatory asset of $244 million includes the $154 million of replacement power costs that were previously recorded as a receivable from NEIL (See "CR3 Outage").

NUCLEAR COST RECOVERY

<u>Levy Nuclear</u>

In 2008, the FPSC granted PEF's petition for an affirmative Determination of Need and related orders requesting cost recovery under Florida's nuclear cost-recovery rule for Levy, together with the associated facilities, including transmission lines and substation facilities. Levy is needed to maintain electric system reliability and integrity, provide fuel and generating diversity, and allow PEF to continue to provide adequate electricity to its customers at a reasonable cost. The proposed Levy units will be advanced passive light water nuclear reactors, each with a generating capacity of approximately 1,100 MW. The petition included projections that Levy Unit No. 1 would be placed in service by June 2016 and Levy Unit No. 2 by June 2017. The filed, nonbinding project cost estimate for Levy Units No. 1 and No. 2 was approximately $14 billion for generating facilities and approximately $3 billion for associated transmission facilities.

In PEF's 2010 nuclear cost-recovery filing (See "Cost Recovery"), PEF identified a schedule shift in the Levy project that resulted from the NRC's 2009 determination that certain schedule-critical work that PEF had proposed to perform within the scope of its Limited Work Authorization request submitted with the COL application will not be authorized until the NRC issues the COL. Consequently, major construction activities on Levy have been postponed until after the NRC issues the COL for the units, which is expected in 2013 if the current licensing schedule remains on track. Along with the FPSC's annual prudence reviews, we will continue to evaluate the project on an ongoing basis based on certain criteria, including, but not limited to, cost; potential carbon regulation; fossil fuel prices; the benefits of fuel diversification; public, regulatory and political support; adequate financial cost-recovery mechanisms; appropriate levels of joint owner participation; customer rate impacts; project feasibility; DSM and EE programs; and availability and terms of capital financing. Taking into account these criteria, we consider Levy to be PEF's preferred baseload generation option.

Crystal River Unit No. 3 Nuclear Plant Uprate

In 2007, the FPSC issued an order approving PEF's Determination of Need petition related to a multi-stage uprate of CR3 that will increase CR3's gross output by approximately 180 MW during its next refueling outage. PEF implemented the first-stage design modifications in 2008. The final stage of the uprate required a license amendment to be filed with the NRC, which was filed by PEF in June 2011 and accepted for review by the NRC on November 21, 2011.

Cost Recovery

In 2009, pursuant to the FPSC nuclear cost-recovery rule, PEF filed a petition to recover $446 million through the CCRC, which primarily consisted of preconstruction and carrying costs incurred or anticipated to be incurred during 2009 and the projected 2010 costs associated with the Levy and CR3 uprate projects. In an effort to help mitigate the initial price impact on its customers, as part of its filing, PEF proposed collecting certain costs over a five-year period, with associated carrying costs on the unrecovered balance. The FPSC approved the alternate proposal allowing PEF to recover revenue requirements associated with the nuclear cost-recovery clause through the CCRC beginning with the first billing cycle of January 2010. The remainder, with minor adjustments, will also be recovered through the CCRC. In adopting PEF's proposed rate management plan for 2010, the FPSC permitted PEF to annually reconsider changes to the recovery of deferred amounts to afford greater flexibility to manage future rate impacts. The rate management plan included the 2009 reclassification to the nuclear cost-recovery clause regulatory asset of $198 million of capacity revenues and the accelerated amortization of $76 million of preconstruction costs. The cumulative amount of $274 million was recorded as a nuclear cost-recovery regulatory asset at December 31, 2009, and is projected to be recovered by the end of 2014. At December 31, 2011, PEF's nuclear cost-recovery regulatory asset was $102 million, comprised of a $15 million current regulatory liability and a $117 million noncurrent regulatory asset. PEF will continue to recover nuclear costs as provided for by the 2012 settlement agreement.

On October 24, 2011, the FPSC approved a $78 million decrease in the amount charged to PEF's ratepayers for nuclear cost recovery, which is a component of, and is included in, the fuel cost recovery (See "Fuel Cost Recovery"), including recovery of preconstruction and carrying costs and CCRC-recoverable O&M expense anticipated to be incurred during 2012, recovery of $60 million of prior years' deferrals in 2012, as well as the estimated actual true-up of 2011 costs associated with the Levy and CR3 uprate projects. Also included is the stipulation of PEF's filed motion with the FPSC to defer until 2012 the approval of the long-term feasibility analysis of completing the CR3 uprate, and the determination of reasonableness on, and recovery of, 2011 and 2012 estimated costs. This resulted in an estimated decrease in the nuclear cost-recovery charge of $2.67 per 1,000 kWh for residential customers, beginning with the first January 2012 billing cycle.

DEMAND-SIDE MANAGEMENT COST RECOVERY

On July 26, 2011, the FPSC voted to set PEF's DSM compliance goals to remain at their current level until the next goal setting docket is initiated. An intervener filed a protest to the FPSC's Proposed Agency Action order, asserting legal challenges to the order. The parties made legal arguments to the FPSC and the FPSC issued an order denying the protest on December 22, 2011. The intervener then filed a notice of appeal of this order to the Florida Supreme Court on January 17, 2012. We cannot predict the outcome of this matter.

On November 1, 2011, the FPSC approved PEF's request to decrease the Energy Conservation Cost Recovery Clause (ECCR) residential rate by $0.11 per 1,000 kWh, or 0.1 percent of the total residential rate, effective January 1, 2012. The decrease in the ECCR is primarily due to an increased refund of a prior period over-recovery, partially offset by an increase in conservation program costs. At December 31, 2011, PEF's over-recovered deferred ECCR balance was $19 million.

OTHER MATTERS

On November 22, 2011, the FPSC approved PEF's request to increase the ECRC by $24 million, increasing the residential rate by $0.54 per 1,000 kWh, or 0.5 percent, effective January 1, 2012. The increase in the ECRC is primarily due to the 2011 rates including a return of a prior period over-recovery, partially offset by a decrease in the related O&M expense. At December 31, 2011, PEF's over-recovered deferred ECRC was $7 million.

On March 20, 2009, PEF filed a petition with the FPSC for expedited approval of the deferral of $53 million in 2009 pension expense. PEF requested that the deferral of pension expense continue until the recovery of these costs is provided for in FPSC-approved base rates. On June 16, 2009, the FPSC approved the deferral of the retail portion of actual 2009 pension expense. As a result of the order, PEF deferred pension expense of $34 million for the year ended December 31, 2009. PEF will not earn a carrying charge on the deferred pension regulatory asset. The deferral of pension expense did not result in a change in PEF's 2009 retail rates or prices. In accordance with the order, subsequent to 2009 PEF will amortize the deferred pension regulatory asset to the extent that annual pension expense is less than the $27 million allowance provided for in the base rates established in the 2010 base rate proceeding. In the event such amortization is insufficient to fully amortize the regulatory asset, PEF can seek recovery of the remaining unamortized amount in a base rate proceeding no earlier than 2015. As of December 31, 2011, PEF has not recorded any amortization related to the deferred pension regulatory asset. The 2012 settlement agreement allows for accelerated amortization of all or part of this deferred pension regulatory asset.

D. NUCLEAR LICENSE RENEWALS

PEC's nuclear units are currently operating under licenses that expire between 2030 and 2046. The NRC operating license held by PEF for CR3 currently expires in December 2016. PEF applied for a 20-year renewal of the license in 2008. The NRC's remaining open items in the license renewal process are associated with the containment structure repair. Once the repair design has been completed and evaluated, the NRC may proceed with the renewal application review of the containment structure. Assuming the repair is successful, management believes CR3 will satisfy the requirements for the license renewal.

9. GOODWILL

Goodwill is required to be tested for impairment at least annually and more frequently when indicators of impairment exist. All of our goodwill is allocated to our utility reporting units and our goodwill impairment tests are performed at the utility reporting unit level. At December 31, 2011 and 2010, our carrying amount of goodwill was $3.655 billion, with $1.922 billion assigned to PEC and $1.733 billion assigned to PEF. The amounts assigned to PEC and PEF are recorded in our Corporate and Other business segment. We perform our annual impairment test as of October 31 of each year. The results of our 2011 annual test of goodwill indicated that the carrying amounts of goodwill were not impaired.

10. EQUITY

A. COMMON STOCK

PROGRESS ENERGY

At December 31, 2011 and December 31, 2010, we had 500 million shares of common stock authorized under our charter, of which 295 million and 293 million shares were outstanding, respectively. We periodically issue shares of common stock through the Progress Energy 401(k) Savings & Stock Ownership Plan (401(k)), the Progress Energy Investor Plus Plan (IPP) and other benefit plans.

There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings (See Note 2 and Note 12B).

The following table presents information for our common stock issuances for the years ended December 31:

	2011		2010		2009	
(in millions)	**Shares**	**Net Proceeds**	Shares	Net Proceeds	Shares	Net Proceeds
Total issuances	**2.0**	**$ 53**	12.2	$ 434	17.5	$ 623
Issuances under an underwritten public offering[(a)]	-	-	-	-	14.4	523
Issuances through 401(k) and/or IPP	-	1	11.2	431	2.5	100

(a)The shares issued under an underwritten public offering were issued on January 12, 2009, at a public offering price of $37.50.

PEC

At December 31, 2011 and December 31, 2010, PEC was authorized to issue up to 200 million shares of common stock. All shares issued and outstanding are held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B for additional dividend restrictions related to PEC.

PEF

At December 31, 2011 and December 31, 2010, PEF was authorized to issue up to 60 million shares of common stock. All PEF common shares issued and outstanding are indirectly held by Progress Energy. There are various provisions limiting the use of retained earnings for the payment of dividends under certain circumstances. At December 31, 2011, there were no significant restrictions on the use of retained earnings. See Note 12B for additional dividend restrictions related to PEF.

B. STOCK-BASED COMPENSATION

EMPLOYEE STOCK OWNERSHIP PLAN

We sponsor the 401(k) for which substantially all full-time nonbargaining unit employees and certain part-time nonbargaining unit employees within participating subsidiaries are eligible. The 401(k), which has a matching feature, 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 share 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 was held by the 401(k) Trustee in a suspense account. The common stock was released from the suspense account and made available for allocation to participants as the ESOP loan was repaid. Such allocations were used to partially meet common stock needs related to matching and incentive contributions and/or reinvested dividends. All or a portion of the dividends paid on ESOP suspense shares and on ESOP shares allocated to participants may be used to repay ESOP acquisition loans. Dividends that are used to repay such loans, paid directly to participants or reinvested by participants, are deductible for income tax purposes. By December 31, 2010, no ESOP suspense shares were outstanding and the ESOP acquisition loan was repaid.

ESOP shares allocated to plan participants totaled 13.4 million at December 31, 2010. Our matching compensation cost under the 401(k) is determined based on matching percentages as defined in the plan. Through December 31, 2010, such compensation cost was allocated to participants' accounts in the form of Progress Energy common stock. Beginning in 2011, such compensation cost was allocated to participants' accounts in the same investments and election percentages as the participants' contributions. In 2010, we met common stock share needs with open market purchases and with shares released from the ESOP suspense account. Matching costs met with shares released from the suspense account totaled $12 million for the years ended December 31, 2010 and 2009, respectively. In 2011, we met common stock share needs with open market purchases.

We also sponsor the Savings Plan for Employees of Florida Progress Corporation, which is an ESOP plan that covers bargaining unit employees of PEF.

Total matching cost for both plans was $44 million, $43 million and $41 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEC

PEC's matching costs met with shares released from the ESOP suspense account totaled $8 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost was $23 million, $23 million and $22 million for the years ended December 31, 2011, 2010 and 2009, respectively.

PEF

PEF's matching costs met with shares released from the ESOP suspense account totaled $3 million and $4 million for the years ended December 31, 2010 and 2009, respectively. Total matching cost for both plans was $14 million, $14 million and $12 million for the years ended December 31, 2011, 2010 and 2009, respectively.

OTHER STOCK-BASED COMPENSATION PLANS

We have additional compensation plans for our officers and key employees that are stock-based in whole or in part. Our long-term compensation program currently includes two types of equity-based incentives: performance shares under the Performance Share Sub-Plan (PSSP) and restricted stock programs. The compensation program was established pursuant to our 1997 Equity Incentive Plan (EIP) and was continued under our 2002 and 2007 EIPs, as amended and restated from time to time. As authorized by the EIPs, we may grant up to 20 million shares of Progress Energy common stock through our long-term compensation program.

Beginning in 2009, shares issued under the redesigned PSSP use total shareholder return and earnings growth as two equally weighted performance measures. The outcome of the performance measures can result in an increase or decrease from the target number of performance shares granted. We distribute common stock shares to participants equivalent to the number of performance shares that ultimately vest. We issue new shares of common stock to satisfy the requirements of the PSSP program. Also, the fair value of the stock-settled award is generally established at the grant date based on the fair value of common stock on that date, with subsequent adjustments made to reflect the status of the performance measure. Compensation expense for all awards is reduced by estimated forfeitures. At December 31, 2011, there were an immaterial number of stock-settled performance target shares outstanding. The final number of shares issued will be dependent upon the outcome of the performance measures discussed above.

Beginning in 2007, we began issuing restricted stock units (RSUs) rather than the previously issued restricted stock awards for our officers, vice presidents, managers and key employees. RSUs awarded to eligible employees are generally subject to either three- or five-year cliff vesting or three- or five-year graded vesting. We issue new shares of common stock to satisfy the requirements of the RSU program. Compensation expense, based on the fair value of common stock at the grant date, is recognized over the applicable vesting period, with corresponding increases in common stock equity. RSUs are included as shares outstanding in the basic earnings per share calculation and are converted to shares upon vesting. At December 31, 2011, there were an immaterial number of RSUs outstanding.

The total fair value of RSUs vested during the years ended December 31, 2011, 2010 and 2009, was $24 million, $24 million and $16 million, respectively. No cash was expended to purchase stock to satisfy RSU plan obligations in 2011, 2010 and 2009. The RSUs vested during 2011 had a weighted-average grant date fair value of $39.16.

Our Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $33 million for the year ended December 31, 2011, with a recognized tax benefit of $13 million. The total expense recognized on our Consolidated Statements of Income for other stock-based compensation plans was $27 million, with a recognized tax benefit of $11 million, and $37 million, with a recognized tax benefit of $14 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

At December 31, 2011, unrecognized compensation cost related to nonvested other stock-based compensation plan awards totaled $33 million, which is expected to be recognized over a weighted-average period of 1.6 years.

PEC

PEC's Consolidated Statements of Income included total recognized expense for other stock-based compensation plans of $20 million for the year ended December 31, 2011, with a recognized tax benefit of $8 million. The total expense recognized on PEC's Consolidated Statements of Income for other stock-based compensation plans was $16 million, with a recognized tax benefit of $6 million, and $22 million, with a recognized tax benefit of $9 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

PEF

PEF's Statements of Income included total recognized expense for other stock-based compensation plans of $13 million for the year ended December 31, 2011, with a recognized tax benefit of $5 million. The total expense recognized on PEF's Statements of Income for other stock-based compensation plans was $11 million, with a recognized tax benefit of $4 million, and $14 million, with a recognized tax benefit of $5 million, for the years ended December 31, 2010 and 2009, respectively. No compensation cost related to other stock-based compensation plans was capitalized.

C. EARNINGS PER COMMON SHARE

Basic earnings per common share are based on the weighted-average number of common shares outstanding, which includes the effects of unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents. Diluted earnings per share include the effects of the nonvested portion of performance share awards and the effect of stock options outstanding.

A reconciliation of the weighted-average number of common shares outstanding for the years ended December 31 for basic and dilutive purposes follows:

(in millions)	**2011**	2010	2009
Weighted-average common shares – basic	**295.8**	290.7	279.4
Net effect of dilutive stock-based compensation plans	**0.1**	0.1	0.1
Weighted-average shares – fully diluted	**295.9**	290.8	279.5

There were no adjustments to net income or to income from continuing operations attributable to controlling interests between the calculations of basic and fully diluted earnings per common share. There were 0.8 million and 1.5 million stock options outstanding at December 31, 2010 and 2009, respectively, which were not included in the weighted-average number of shares for computing the fully diluted earnings per share because they were antidilutive. As of December 31, 2011, there were no antidilutive stock options outstanding.

D. ACCUMULATED OTHER COMPREHENSIVE LOSS

Components of accumulated other comprehensive loss, net of tax, at December 31 were as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Cash flow hedges	**$ (143)**	$ (63)	**$ (71)**	$ (33)	**$ (27)**	$ (4)
Pension and other postretirement benefits	**(22)**	(62)	**-**	-	**-**	-
Total accumulated other comprehensive loss	**$ (165)**	$ (125)	**$ (71)**	$ (33)	**$ (27)**	$ (4)

11. PREFERRED STOCK OF SUBSIDIARIES

All of our preferred stock was issued by the Utilities. The preferred stock is considered temporary equity due to certain provisions that could require us to redeem the preferred stock for cash. In the event dividends payable on PEC or PEF preferred stock are in default for an amount equivalent to or exceeding four quarterly dividend payments, the holders of the preferred stock are entitled to elect a majority of PEC's or PEF's respective board of directors until all accrued and unpaid dividends are paid. All classes of preferred stock are entitled to cumulative dividends with preference to the common stock dividends, are redeemable by vote of the Utilities' respective board of directors at any time, and do not have any preemptive rights. All classes of preferred stock have a liquidation preference equal to $100 per share plus any accumulated unpaid dividends except for PEF's 4.75%, $100 par value class, which does not have a liquidation preference. Each holder of PEC's preferred stock is entitled to one vote. The holders of PEF's preferred stock have no right to vote except for certain circumstances involving dividends payable on preferred stock that are in default or certain matters affecting the rights and preferences of the preferred stock.

At December 31, 2011 and 2010, preferred stock outstanding consisted of the following:

	Shares			
(dollars in millions, except share and per share data)	Authorized	Outstanding	Redemption Price	Total
PEC				
Cumulative, no par value $5 Preferred Stock	300,000	236,997	$ 110.00	$ 24

Cumulative, no par value Serial Preferred Stock	20,000,000			
$4.20 Serial Preferred		100,000	102.00	10
$5.44 Serial Preferred		249,850	101.00	25
Cumulative, no par value Preferred Stock A	5,000,000	-	-	-
No par value Preference Stock	10,000,000	-	-	-
Total PEC				59
PEF				
Cumulative, $100 par value Preferred Stock	4,000,000			
4.00% $100 par value Preferred		39,980	104.25	4
4.40% $100 par value Preferred		75,000	102.00	8
4.58% $100 par value Preferred		99,990	101.00	10
4.60% $100 par value Preferred		39,997	103.25	4
4.75% $100 par value Preferred		80,000	102.00	8
Cumulative, no par value Preferred Stock	5,000,000	-	-	-
$100 par value Preference Stock	1,000,000	-	-	-
Total PEF				34
Total preferred stock of subsidiaries				$ 93

12. DEBT AND CREDIT FACILITIES

A. DEBT AND CREDIT FACILITIES

At December 31 our long-term debt consisted of the following (maturities and weighted-average interest rates at December 31, 2011):

(in millions)		2011	2010
Parent			
Senior unsecured notes, maturing 2012-2039	6.28 %	**$ 4,000**	$ 4,200
Unamortized premium and discount, net		**(7)**	(6)
Current portion of long-term debt		**(450)**	(205)
Long-term debt, net		**3,543**	3,989
PEC			
First mortgage bonds, maturing 2013-2038	5.17 %	**3,025**	2,525
First mortgage bonds/pollution control obligations, maturing 2017-2024	0.57 %	**669**	669
Senior unsecured notes, maturing 2012	6.50 %	**500**	500
Miscellaneous notes	6.00 %	**5**	5
Unamortized premium and discount, net		**(6)**	(6)
Current portion of long-term debt		**(500)**	-
Long-term debt, net		**3,693**	3,693
PEF			
First mortgage bonds, maturing 2013-2040	5.56 %	**4,100**	4,100
First mortgage bonds/pollution control obligations, maturing 2018-2027	0.57 %	**241**	241
Medium-term notes, maturing 2028	6.75 %	**150**	150
Unamortized premium and discount, net		**(9)**	(9)
Current portion of long-term debt		**-**	(300)
Long-term debt, net		**4,482**	4,182
Progress Energy consolidated long-term debt, net		**$ 11,718**	$ 11,864
Florida Progress Funding Corporation (See Note 23)			
Debt to affiliated trust, maturing 2039	7.10 %	**$ 309**	$ 309
Unamortized premium and discount, net		**(36)**	(36)
Long-term debt, affiliate		**$ 273**	$ 273

On January 21, 2011, the Parent issued $500 million of 4.40% Senior Notes due January 15, 2021. The net proceeds of $495 million, along with available cash on hand, were used to retire the $700 million outstanding aggregate principal balance of our 7.10% Senior Notes due March 1, 2011. Accordingly, we classified $495 million of the Parent's $700 million 7.10% Senior Notes due March 1, 2011 as long-term debt at December 31, 2010.

On July 15, 2011, PEF paid at maturity $300 million of its 6.65% First Mortgage Bonds with proceeds from short-term debt.

On August 18, 2011, PEF issued $300 million 3.10% First Mortgage Bonds due August 15, 2021. The net proceeds were used to repay a portion of outstanding short-term debt, of which $300 million was issued to repay PEF's July 15, 2011 maturity.

On September 15, 2011, PEC issued $500 million 3.00% First Mortgage Bonds due September 15, 2021. A portion of the net proceeds was used to repay outstanding short-term debt and the remainder was used for general corporate purposes, including construction expenditures.

On January 15, 2010, the Parent paid at maturity $100 million of its Series A Floating Rate Notes with a portion of the proceeds from the $950 million of Senior Notes issued on November 19, 2009.

On March 25, 2010, PEF issued $250 million of 4.55% First Mortgage Bonds due April 1, 2020, and $350 million of 5.65% First Mortgage Bonds due April 1, 2040. Proceeds were used to repay the outstanding balance of PEF's notes payable to affiliated companies, to repay the maturity of PEF's $300 million 4.50% First Mortgage Bonds due June 1, 2010, and for general corporate purposes.

At December 31, 2011 and 2010, we had committed lines of credit used to support our commercial paper and other short-term borrowings. At December 31, 2011 and 2010, we had no outstanding borrowings under our revolving credit agreements (RCAs). We are required to pay fees to maintain our credit facilities.

The following tables summarize our RCAs and available capacity at December 31:

(in millions)		Total	Outstanding	Reserved[(a)]	Available
2011					
Parent	**Five-year (expiring 5/3/12)[(b)]**	**$ 478**	**$ -**	**$ 252**	**$ 226**
PEC	**Three-year (expiring 10/15/13)**	**750**	**-**	**184**	**566**
PEF	**Three-year (expiring 10/15/13)**	**750**	**-**	**233**	**517**
Total credit facilities		**$ 1,978**	**$ -**	**$ 669**	**$ 1,309**
2010					
Parent	Five-year (expiring 5/3/12)	$ 500	$ -	$ 31	$ 469
PEC	Three-year (expiring 10/15/13)	750	-	-	750
PEF	Three-year (expiring 10/15/13)	750	-	-	750
Total credit facilities		$ 2,000	$ -	$ 31	$ 1,969

(a) To the extent amounts are reserved for commercial paper or letters of credit outstanding, they are not available for additional borrowings. At December 31, 2011 and 2010, the Parent had issued $2 million and $31 million, respectively, of letters of credit supported by the RCA. Additionally, on December 31, 2011, the Parent, PEC and PEF had $250 million, $184 million and $233 million, respectively, of outstanding commercial paper supported by the RCA.
(b) On February 15, 2012, the Parent's RCA was amended to extend its expiration date to May 3, 2013.

The combined RCAs of the Parent, PEC and PEF total $1.978 billion and are supported by 23 financial institutions. The RCAs are used to provide liquidity support for issuances of commercial paper and other short-term obligations, and for general corporate purposes. Fees and interest rates under the RCAs are determined based upon the respective credit ratings of the Parent's, PEC's and PEF's long-term unsecured senior noncredit-enhanced debt, as rated by Moody's Investor Services, Inc. (Moody's) and Standard & Poor's Rating Services (S&P). The RCAs do not include material adverse change representations for borrowings or financial covenants for interest coverage.

The Parent entered into a five-year RCA on May 3, 2006. On May 2, 2008, the expiration date of the RCA was extended to May 3, 2012. The Parent ratably reduced the size of the RCA to $500 million on October 15, 2010, and the RCA was further reduced to $478 million on May 3, 2011, following the expiration of one financial institution's credit commitment. On February 15, 2012, the Parent's $478 million RCA was amended to extend the expiration date from May 3, 2012, to May 3, 2013, with its existing syndicate of 14 financial institutions.

PEC and PEF entered into $750 million, three-year RCAs with a syndication of 22 financial institutions on October 15, 2010. The RCAs, which expire October 15, 2013, replaced PEC's and PEF's previous RCAs, which were set to expire on June 28, 2011, and March 28, 2011, respectively.

See "Covenants and Default Provisions" for additional provisions related to the RCAs.

The following table summarizes short-term debt, comprised of outstanding commercial paper and other miscellaneous short-term debt, and related weighted-average interest rates at December 31:

(in millions)	2011			2010		
Parent	**0.50 %**	**$**	**250**	- %	$	-
PEC	**0.49**		**188**	-		-
PEF	**0.51**		**233**	-		-
Total	**0.50 %**	**$**	**671**	- %	$	-

Long-term debt maturities during the next five years are as follows:

(in millions)	Progress Energy Consolidated	PEC	PEF
2012	$ 950	$ 500	$ -
2013	830	405	425
2014	300	-	-
2015	1,000	700	300
2016	300	-	-

B. COVENANTS AND DEFAULT PROVISIONS

FINANCIAL COVENANTS

The Parent's, PEC's and PEF's credit lines contain various terms and conditions that could affect the ability to borrow under these facilities. All of the credit facilities include a defined maximum total debt to total capitalization ratio (leverage). At December 31, 2011, the maximum and calculated ratios for the Progress Registrants, pursuant to the terms of the agreements, were as follows:

Company	Maximum Ratio	Actual Ratio[(a)]
Parent	68 %	58 %
PEC	65 %	46 %
PEF	65 %	51 %

(a) Indebtedness as defined by the credit agreement includes certain letters of credit, surety bonds and guarantees not recorded on the Consolidated Balance Sheets.

CROSS-DEFAULT PROVISIONS

Each of these credit agreements contains cross-default provisions for defaults of indebtedness in excess of the following thresholds: $50 million for the Parent and $35 million each for PEC and PEF. Under these provisions, if the applicable borrower or certain subsidiaries of the borrower fail to pay various debt obligations in excess of their respective cross-default threshold, the lenders of that credit facility could accelerate payment of any outstanding borrowing and terminate their commitments to the credit facility. The

Parent's cross-default provision can be triggered by the Parent and its significant subsidiaries, as defined in the credit agreement. PEC's and PEF's cross-default provisions can be triggered only by defaults of indebtedness by PEC and its subsidiaries and PEF, respectively, not by each other or by other affiliates of PEC and PEF.

Additionally, certain of the Parent's long-term debt indentures contain cross-default provisions for defaults of indebtedness in excess of amounts ranging from $25 million to $50 million; these provisions apply only to other obligations of the Parent, primarily commercial paper issued by the Parent, not its subsidiaries. In the event that these indenture cross-default provisions are triggered, the debt holders could accelerate payment of approximately $4.000 billion in long-term debt. Certain agreements underlying our indebtedness also limit our ability to incur additional liens or engage in certain types of sale and leaseback transactions.

OTHER RESTRICTIONS

Neither the Parent's Articles of Incorporation nor any of its debt obligations contain any restrictions on the payment of dividends, so long as no shares of preferred stock are outstanding. At December 31, 2011, the Parent had no shares of preferred stock outstanding. See Note 2 for information regarding restrictions on dividends relative to the Progress Energy and Duke Energy Agreement and Plan of Merger.

Certain documents restrict the payment of dividends by the Parent's subsidiaries as outlined below.

PEC

PEC's mortgage indenture provides that as long as any first mortgage bonds are outstanding, cash dividends and distributions on its common stock and purchases of its common stock are restricted to aggregate net income available for PEC since December 31, 1948, plus $3 million, less the amount of all preferred stock dividends and distributions, and all common stock purchases, since December 31, 1948. At December 31, 2011, none of PEC's cash dividends or distributions on common stock was restricted.

In addition, PEC's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, the aggregate amount of cash dividends or distributions on common stock since December 31, 1945, including the amount then proposed to be expended, shall be limited to 75 percent of the aggregate net income available for common stock if common stock equity falls below 25 percent of total capitalization, as defined by PEC's Articles of Incorporation, and to 50 percent if common stock equity falls below 20 percent. PEC's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, and to 50 percent if common stock equity falls below 20 percent. At December 31, 2011, PEC's common stock equity was approximately 57.6 percent of total capitalization. At December 31, 2011, none of PEC's cash dividends or distributions on common stock was restricted.

PEF

PEF's mortgage indenture provides that as long as any first mortgage bonds are outstanding, 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, 2011, none of PEF's cash dividends or distributions on common stock was restricted.

In addition, PEF's Articles of Incorporation provide that so long as any shares of preferred stock are outstanding, 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, exceeds all credits to retained earnings since April 30, 1944, plus all amounts credited to capital surplus after April 30, 1944, arising from the donation to PEF of cash or securities or transfers of amounts from retained earnings to capital surplus. PEF's Articles of Incorporation also provide that cash dividends on common stock shall be limited to 75 percent of the current year's net income available for dividends if common stock equity falls below 25 percent of total capitalization, as defined by PEF's Articles of Incorporation, and to 50 percent if common stock equity falls below 20 percent. On December 31, 2011, PEF's common stock equity was approximately 50.9 percent of total capitalization. At

December 31, 2011, none of PEF's cash dividends or distributions on common stock was restricted.

C. COLLATERALIZED OBLIGATIONS

PEC's and PEF's first mortgage bonds, including pollution control obligations, are collateralized by their respective mortgage indentures. Each mortgage constitutes a first lien on substantially all of the fixed properties of the respective company, subject to certain permitted encumbrances and exceptions. Each mortgage also constitutes a lien on subsequently acquired property. At December 31, 2011, PEC and PEF had a total of $3.694 billion and $4.341 billion, respectively, of first mortgage bonds outstanding, including those related to pollution control obligations.

Each mortgage allows the issuance of additional first mortgage bonds based on property additions, retirements of first mortgage bonds and the deposit of cash if certain conditions are satisfied. Most first mortgage bond issuances by PEC and PEF require that adjusted net earnings be at least twice the annual interest requirement for bonds currently outstanding and to be outstanding. PEF's ratio of net earnings to the annual interest requirement for bonds outstanding was below 2.0 times at December 31, 2011. PEF's 2011 net earnings were impacted by a $288 million charge recorded in December 2011 for amounts to be refunded to customers (See Note 8C). Until this ratio, which is calculated based on results for 12 consecutive months, is above 2.0 times, PEF's capacity to issue first mortgage bonds is limited to a portion of retired first mortgage bonds. In the event PEF's long-term debt requirements exceed its first mortgage bond capacity, it could issue unsecured debt.

D. GUARANTEES OF SUBSIDIARY DEBT

See Note 19 on related party transactions for a discussion of obligations guaranteed or secured by affiliates.

E. HEDGING ACTIVITIES

We use interest rate derivatives to adjust the fixed and variable rate components of our debt portfolio and to hedge cash flow risk related to commercial paper and fixed-rate debt to be issued in the future. See Note 18 for a discussion of risk management activities and derivative transactions.

13. INVESTMENTS

A. INVESTMENTS

At December 31, 2011 and 2010, we had investments in various debt and equity securities, cost investments, company-owned life insurance and investments held in trust funds as follows:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Nuclear decommissioning trust (See Notes 5C and 14)	**$ 1,647**	$ 1,571	**$ 1,088**	$ 1,017	**$ 559**	$ 554
Equity method investments[(a)]	**14**	16	**1**	3	**2**	2
Cost investments[(b)]	**2**	5	**2**	4	**-**	-
Company-owned life insurance[(c)]	**47**	46	**39**	37	**-**	-
Benefit investment trusts[(d)]	**176**	175	**105**	97	**37**	37
Total	**$ 1,886**	$ 1,813	**$ 1,235**	$ 1,158	**$ 598**	$ 593

(a) Investments in unconsolidated companies are accounted for using the equity method of accounting (See Note 1) and are included in miscellaneous other property and investments on the Consolidated Balance Sheets. These investments are primarily in limited liability corporations and limited partnerships, and the earnings from these investments are recorded on a pre-tax basis.
(b) Investments stated principally at cost are included in miscellaneous other property and investments on the Consolidated Balance Sheets.
(c) Investments in company-owned life insurance approximate fair value due to the nature of the investments and are included in miscellaneous other property and investments on the Consolidated Balance Sheets.
(d) Benefit investment trusts are included in miscellaneous other property and investments on the Consolidated Balance Sheets. At December 31, 2011 and 2010, $173 million and $166 million, respectively, of investments in company-owned life insurance were held in Progress Energy's trusts. Substantially all of PEC's and PEF's benefit investment trusts are invested in company-owned life insurance.

B. IMPAIRMENT OF INVESTMENTS

Declines in fair value of available-for-sale securities to below the cost basis that are judged to be other than temporary are included in long-term regulatory assets or liabilities on the Consolidated Balance Sheets for securities held in our nuclear decommissioning trust funds and in operation and maintenance expense and other, net on the Consolidated Statements of Income for securities in our benefit investment trusts, other available-for-sale securities and equity and cost method investments. See Note 14 for additional information. There were no material other-than-temporary impairments recognized in earnings in 2011, 2010 or 2009.

14. <u>FAIR VALUE DISCLOSURES</u>

A. DEBT AND INVESTMENTS

PROGRESS ENERGY

DEBT

The carrying amount of our long-term debt, including current maturities, was $12.941 billion and $12.642 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $15.3 billion and $14.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. Our available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning the Utilities' nuclear plants (See Note 5C). NDT funds are presented on the Consolidated Balance Sheets at fair value. In addition to the NDT funds, we hold other debt investments classified as available-for-sale, which are included in miscellaneous other property and investments on the Consolidated Balance Sheets at fair value.

The following table summarizes our available-for-sale securities at December 31:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 1,033**	**$ 29**	**$ 401**
Preferred stock and other equity	**29**	**-**	**11**
Corporate debt	**86**	**-**	**6**
U.S. state and municipal debt	**128**	**2**	**7**
U.S. and foreign government debt	**284**	**-**	**18**
Money market funds and other	**70**	**-**	**1**
Total	**$ 1,630**	**$ 31**	**$ 444**
2010			
Common stock equity	$ 1,021	$ 13	$ 408
Preferred stock and other equity	28	-	11
Corporate debt	90	-	6
U.S. state and municipal debt	132	4	3
U.S. and foreign government debt	264	2	10
Money market funds and other	52	-	1
Total	$ 1,587	$ 19	$ 439

The NDT funds and other available-for-sale debt investments held in certain benefit trusts are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and unrealized gains for 2011 and 2010 relate to the NDT funds. There were no material unrealized losses and unrealized gains for the other available-for-sale debt securities held in benefit trusts at December 31, 2011 and 2010.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $136 million and $195 million, respectively.

At December 31, 2011, the fair value of our available-for-sale debt securities by contractual maturity was:

(in millions)		
Due in one year or less	$	44
Due after one through five years		231
Due after five through 10 years		147
Due after 10 years		90
Total	$	512

The following table presents selected information about our sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)		2011		2010		2009
Proceeds	**$**	**4,640**	$	6,747	$	2,207
Realized gains		**30**		21		26
Realized losses		**33**		27		87

Proceeds were primarily related to NDT funds. Realized gains and losses for investments in the benefit investment trusts were not material. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, our other securities had no investments in a continuous loss position for greater than 12 months.

PEC

DEBT

The carrying amount of PEC's long-term debt, including current maturities, was $4.193 billion and $3.693 billion at December 31, 2011 and 2010, respectively. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $4.7 billion and $4.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEC's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEC's nuclear plants (See Note 5C). NDT funds are presented on the Consolidated Balance Sheets at fair value.

The following table summarizes PEC's available-for-sale securities at December 31:

(in millions)	Fair Value	Unrealized Losses	Unrealized Gains
2011			
Common stock equity	**$ 673**	**$ 20**	**$ 255**
Preferred stock and other equity	**17**	**-**	**7**
Corporate debt	**69**	**-**	**5**
U.S. state and municipal debt	**56**	**-**	**3**
U.S. and foreign government debt	**226**	**-**	**16**
Money market funds and other	**60**	**-**	**1**
Total	**$ 1,101**	**$ 20**	**$ 287**
2010			
Common stock equity	$ 652	$ 10	$ 256
Preferred stock and other equity	14	-	6
Corporate debt	72	-	5
U.S. state and municipal debt	51	1	1
U.S. and foreign government debt	199	1	9
Money market funds and other	42	-	1
Total	$ 1,030	$ 12	$ 278

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include the unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $98 million and $104 million, respectively.

At December 31, 2011, the fair value of PEC's available-for-sale debt securities by contractual maturity was:

(in millions)	
Due in one year or less	$ 16
Due after one through five years	184
Due after five through 10 years	100
Due after 10 years	62
Total	$ 362

The following table presents selected information about PEC's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)	**2011**	2010	2009
Proceeds	**$ 496**	$ 419	$ 622
Realized gains	**13**	10	9
Realized losses	**16**	19	36

PEC's proceeds were primarily related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, PEC did not have any other securities.

PEF

DEBT

The carrying amount of PEF's long-term debt, including current maturities, was $4.482 billion at December 31, 2011 and 2010. The estimated fair value of this debt, as obtained from quoted market prices for the same or similar issues, was $5.4 billion and $5.0 billion at December 31, 2011 and 2010, respectively.

INVESTMENTS

Certain investments in debt and equity securities that have readily determinable market values are accounted for as available-for-sale securities at fair value. PEF's available-for-sale securities include investments in stocks, bonds and cash equivalents held in trust funds, pursuant to NRC requirements, to fund certain costs of decommissioning PEF's nuclear plant (See Note 5C). The NDT funds are presented on the Balance Sheets at fair value.

The following table summarizes PEF's available-for-sale securities at December 31:

(in millions)		Fair Value		Unrealized Losses		Unrealized Gains
2011						
Common stock equity	**$**	**360**	**$**	**9**	**$**	**146**
Preferred stock and other equity		**12**		**-**		**4**
Corporate debt		**17**		**-**		**1**
U.S. state and municipal debt		**72**		**2**		**4**
U.S. and foreign government debt		**58**		**-**		**2**
Money market funds and other		**10**		**-**		**-**
Total	**$**	**529**	**$**	**11**	**$**	**157**
2010						
Common stock equity	$	369	$	3	$	152
Preferred stock and other equity		14		-		5
Corporate debt		14		-		1
U.S. state and municipal debt		81		3		2
U.S. and foreign government debt		62		1		1
Money market funds and other		10		-		-
Total	$	550	$	7	$	161

The NDT funds are managed by third-party investment managers who have a right to sell securities without our authorization. Net unrealized gains and losses of the NDT funds that would be recorded in earnings or other comprehensive income by a nonregulated entity are recorded as regulatory assets and liabilities pursuant to ratemaking treatment. Therefore, the preceding tables include unrealized gains and losses for the NDT funds based on the original cost of the trust investments. All of the unrealized losses and gains for 2011 and 2010 relate to the NDT funds.

The aggregate fair value of investments that related to the December 31, 2011 and 2010 unrealized losses was $38 million and $87 million, respectively.

At December 31, 2011, the fair value of PEF's available-for-sale debt securities by contractual maturity was:

(in millions)		
Due in one year or less	$	28
Due after one through five years		47
Due after five through 10 years		47
Due after 10 years		28
Total	$	150

The following table presents selected information about PEF's sales of available-for-sale securities for the years ended December 31. Realized gains and losses were determined on a specific identification basis.

(in millions)		**2011**	2010	2009
Proceeds	$	**4,130** $	6,170 $	1,471
Realized gains		**17**	10	14
Realized losses		**17**	8	50

PEF's proceeds were related to NDT funds. Other securities are evaluated on an individual basis to determine if a decline in fair value below the carrying value is other-than-temporary. At December 31, 2011 and 2010, PEF did not have any other securities.

B. FAIR VALUE MEASUREMENTS

GAAP defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (i.e., an exit price). Fair value measurements require the use of market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, corroborated by market data or generally unobservable. Valuation techniques are required to maximize the use of observable inputs and minimize the use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

GAAP also establishes a fair value hierarchy that prioritizes the inputs used to measure fair value, and requires fair value measurements to be categorized based on the observability of those inputs. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 inputs) and the lowest priority to unobservable inputs (Level 3 inputs). The three levels of the fair value hierarchy are as follows:

Level 1 – The pricing inputs are unadjusted quoted prices in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities.

Level 2 – The pricing inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 2 includes financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in this category include non-exchange-traded derivatives, such as over-the-counter forwards, swaps and options; certain marketable debt securities; and financial instruments traded in less than active markets.

Level 3 – The pricing inputs include significant inputs generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value. Level 3 instruments may include longer-term instruments that extend into periods in which quoted prices or other observable inputs are not available.

Certain assets and liabilities, including long-lived assets, were measured at fair value on a nonrecurring basis. There were no significant fair value measurement losses recognized for such assets and liabilities in the periods reported. These fair value measurements fall within Level 3 of the hierarchy discussed above.

The following tables set forth, by level within the fair value hierarchy, our and the Utilities' financial assets and liabilities accounted for at fair value on a recurring basis as of December 31, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

PROGRESS ENERGY

(in millions)	Level 1	Level 2	Level 3	Total
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 1,033	$ -	$ -	$ 1,033
Preferred stock and other equity	28	1	-	29
Corporate debt	-	86	-	86
U.S. state and municipal debt	-	128	-	128
U.S. and foreign government debt	87	197	-	284
Money market funds and other	-	87	-	87
Total nuclear decommissioning trust funds	1,148	499	-	1,647
Derivatives				
Commodity forward contracts	-	5	-	5
Other marketable securities				
Money market and other	20	-	-	20
Total assets	$ 1,168	$ 504	$ -	$ 1,672
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 668	$ 24	$ 692
Interest rate contracts	-	93	-	93
Contingent value obligations	-	14	-	14
Total liabilities	$ -	$ 775	$ 24	$ 799

(in millions)		Level 1		Level 2		Level 3		Total
2010								
Assets								
Nuclear decommissioning trust funds								
Common stock equity	$	1,021	$	-	$	-	$	1,021
Preferred stock and other equity		22		6		-		28
Corporate debt		-		86		-		86
U.S. state and municipal debt		-		132		-		132
U.S. and foreign government debt		79		182		-		261
Money market funds and other		1		42		-		43
Total nuclear decommissioning trust funds		1,123		448		-		1,571
Derivatives								
Commodity forward contracts		-		15		-		15
Interest rate contracts		-		4		-		4
Other marketable securities								
Corporate debt		-		4		-		4
U.S. and foreign government debt		-		3		-		3
Money market and other		18		-		-		18
Total assets	$	1,141	$	474	$	-	$	1,615
Liabilities								
Derivatives								
Commodity forward contracts	$	-	$	458	$	36	$	494
Interest rate contracts		-		39		-		39
Contingent value obligations		-		15		-		15
Total liabilities	$	-	$	512	$	36	$	548

PEC

(in millions)	Level 1	Level 2	Level 3	Total

	Level 1	Level 2	Level 3	Total
2011				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 673	$ -	$ -	$ 673
Preferred stock and other equity	17	-	-	17
Corporate debt	-	69	-	69
U.S. state and municipal debt	-	56	-	56
U.S. and foreign government debt	81	145	-	226
Money market funds and other	-	47	-	47
Total nuclear decommissioning trust funds	771	317	-	1,088
Other marketable securities	6	-	-	6
Total assets	$ 777	$ 317	$ -	$ 1,094
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 177	$ 24	$ 201
Interest rate contracts	-	47	-	47
Total liabilities	$ -	$ 224	$ 24	$ 248

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 652	$ -	$ -	$ 652
Preferred stock and other equity	14	-	-	14
Corporate debt	-	72	-	72
U.S. state and municipal debt	-	51	-	51
U.S. and foreign government debt	76	123	-	199
Money market funds and other	1	28	-	29
Total nuclear decommissioning trust funds	743	274	-	1,017
Derivatives				
Commodity forward contracts	-	2	-	2
Interest rate contracts	-	3	-	3
Other marketable securities	4	-	-	4
Total assets	$ 747	$ 279	$ -	$ 1,026
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 87	$ 36	$ 123
Interest rate contracts	-	11	-	11
Total liabilities	$ -	$ 98	$ 36	$ 134

PEF

(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				

	Level 1	Level 2	Level 3	Total
Nuclear decommissioning trust funds				
Common stock equity	$ 360	$ -	$ -	$ 360
Preferred stock and other equity	11	1	-	12
Corporate debt	-	17	-	17
U.S. state and municipal debt	-	72	-	72
U.S. and foreign government debt	6	52	-	58
Money market funds and other	-	40	-	40
Total nuclear decommissioning trust funds	377	182	-	559
Derivatives				
Commodity forward contracts	-	5	-	5
Other marketable securities	1	-	-	1
Total assets	$ 378	$ 187	$ -	$ 565
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 491	$ -	$ 491
Interest rate contracts	-	8	-	8
Total liabilities	$ -	$ 499	$ -	$ 499

(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Nuclear decommissioning trust funds				
Common stock equity	$ 369	$ -	$ -	$ 369
Preferred stock and other equity	8	6	-	14
Corporate debt	-	14	-	14
U.S. state and municipal debt	-	81	-	81
U.S. and foreign government debt	3	59	-	62
Money market funds and other	-	14	-	14
Total nuclear decommissioning trust funds	380	174	-	554
Derivatives				
Commodity forward contracts	-	13	-	13
Other marketable securities	1	-	-	1
Total assets	$ 381	$ 187	$ -	$ 568
Liabilities				
Derivatives				
Commodity forward contracts	$ -	$ 371	$ -	$ 371
Interest rate contracts	-	7	-	7
Total liabilities	$ -	$ 378	$ -	$ 378

The determination of the fair values in the preceding tables incorporates various factors, including risks of nonperformance by us or our counterparties. Such risks consider not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits or letters of credit), but also the impact of our and the Utilities' credit risk on our liabilities.

Commodity forward contract derivatives and interest rate contract derivatives reflect positions held by us and the Utilities. Most over-the-counter commodity forward contract derivatives and interest rate contract derivatives are valued using financial models which utilize observable inputs for similar instruments and are classified within Level 2. Other derivatives are valued utilizing inputs that are not observable for substantially the full term of the contract, or for which the impact of the unobservable period is significant to the fair value of the derivative. Such derivatives are classified within Level 3. See Note 18 for discussion of risk management activities and derivative transactions.

NDT funds reflect the assets of the Utilities' nuclear decommissioning trusts. The assets of the trusts are invested primarily in exchange-traded equity securities (classified within Level 1) and marketable debt securities, most of which are valued using Level 1 inputs for similar instruments and are classified within Level 2.

Other marketable securities primarily represent available-for-sale debt securities used to fund certain employee benefit costs.

Contingent Value Obligations (CVOs), which are derivatives, are discussed further in Note 16. At September 30, 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement (a Level 3 input) and classified CVOs as Level 3 at that date. Prior to September 30, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market and classified as Level 2. In November 2011, we commenced a public tender offer that expired on February 15, 2012. All CVOs not tendered as of December 31, 2011, were classified as Level 2 based on observable prices in the less-than-active market.

Transfers in (out) of Levels 1, 2 or 3 represent existing assets or liabilities previously categorized as a higher level for which the inputs to the estimate became less observable or assets and liabilities that were previously classified as Level 2 or 3 for which the lowest significant input became more observable during the period. There were no significant transfers in (out) of Levels 1, 2 and 3 during the period other than the CVO transfer previously discussed. Transfers into and out of each level are measured at the end of the period.

A reconciliation of changes in the fair value of our and the Utilities' derivatives, net classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

PROGRESS ENERGY

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ 36**	$ 39	$ 41
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**21**	44	13
Repurchases of CVOs under settlement and tender offer	**(60)**	-	-
Transfers into Level 3 – CVOs	**74**	-	-
Transfers out of Level 3 – CVOs	**(14)**	-	-
Transfers in (out) of Level 3, net – commodities	**(33)**	(47)	(15)
Derivatives, net at end of period	**$ 24**	$ 36	$ 39

PEC

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ 36**	$ 27	$ 22
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**20**	27	7
Transfers in (out) of Level 3, net – commodities	**(32)**	(18)	(2)
Derivatives, net at end of period	**$ 24**	$ 36	$ 27

PEF

(in millions)	**2011**	2010	2009
Derivatives, net at beginning of period	**$ -**	$ 12	$ 19
Total losses (gains), realized and unrealized – commodities deferred as regulatory assets and liabilities, net	**1**	17	6

Transfers in (out) of Level 3, net – commodities	(1)	(29)	(13)
Derivatives, net at end of period	$ -	$ -	$ 12

Substantially all unrealized gains and losses on the Utilities' derivatives are deferred as regulatory liabilities or assets consistent with ratemaking treatment. Realized and unrealized losses on the change in fair value of our CVOs are discussed in Note 18.

15. INCOME TAXES

We provide deferred income taxes for temporary 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 is different from the recovery of taxes by the Utilities through the ratemaking process, the differences are deferred pursuant to GAAP for regulated operations. A regulatory asset or liability has been recognized for the impact of tax expenses or benefits that are recovered or refunded in different periods by the Utilities pursuant to rate orders. We accrue for uncertain tax positions when it is determined that it is more likely than not that the benefit will not be sustained on audit by the taxing authority based solely on the technical merits of the associated tax position. If the recognition threshold is met, the tax benefit recognized is measured at the largest amount that, in our judgment, is greater than 50 percent likely to be realized.

PROGRESS ENERGY

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2011**	2010
Deferred income tax assets		
Derivative instruments	**$ 309**	$ 204
Income taxes refundable through future rates	**375**	271
Pension and other postretirement benefits	**591**	447
Other	**522**	501
Tax credit carry forwards	**872**	839
Net operating loss carry forwards	**291**	105
Valuation allowance	**(71)**	(60)
Total deferred income tax assets	**2,889**	2,307
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(3,098)**	(2,439)
Income taxes recoverable through future rates	**(1,271)**	(875)
Other	**(303)**	(386)
Total deferred income tax liabilities	**(4,672)**	(3,700)
Total net deferred income tax liabilities	**$ (1,783)**	$ (1,393)

The above amounts were classified on the Consolidated Balance Sheets as follows:

(in millions)	**2011**	2010
Current deferred income tax assets, included in deferred tax assets	**$ 371**	$ 156
Noncurrent deferred income tax assets, included in other assets and deferred debits	**27**	34
Noncurrent deferred income tax liabilities, included in noncurrent income tax		

liabilities	**(2,181)**	(1,583)
Total net deferred income tax liabilities	**$ (1,783)**	$ (1,393)

At December 31, 2011, we had the following tax credit and net operating loss carry forwards:

- $868 million of federal alternative minimum tax credits that do not expire.
- $4 million of federal general business credits that will expire during the period 2028 through 2031.
- $623 million of gross federal net operating loss carry forwards that will expire during 2031. $14 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1.9 billion of gross state net operating loss carry forwards that will expire during the period 2012 through 2031.

Valuation allowances have been established due to the uncertainty of realizing certain future state tax benefits. We had a net increase of $11 million in our deferred income tax assets and valuation allowances during 2011 related to prior year state net operating loss carry forwards at Progress Fuels Corporation.

We believe 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.

Certain substantial changes in ownership of Progress Energy, including the proposed merger between Progress Energy and Duke Energy (See Note 2), can impact the timing of the utilization of tax credit carry forwards and net operating loss carry forwards.

Reconciliations of our effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2011	2010	2009
Effective income tax rate	**35.6 %**	38.3 %	32.1 %
State income taxes, net of federal benefit	**(4.3)**	(4.3)	(3.7)
Investment tax credit amortization	**0.8**	0.5	0.8
Employee stock ownership plan dividends	**1.4**	0.9	1.0
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**2.6**	1.4	2.2
Other differences, net	**(1.1)**	(1.8)	1.8
Statutory federal income tax rate	**35.0 %**	35.0 %	35.0 %

Income tax expense applicable to continuing operations for the years ended December 31 was comprised of:

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (91)**	$ (46)	$ 227

State	**29**	(13)	41
Total current income tax expense (benefit)	**(62)**	(59)	268
Deferred			
Federal	**578**	542	114
State	**27**	100	25
Total deferred income tax expense	**605**	642	139
Investment tax credit	**(7)**	(7)	(10)
Net operating loss carry forward	**(213)**	(37)	-
Total income tax expense	**$ 323**	$ 539	$ 397

Total income tax expense applicable to continuing operations excluded the following:

- Taxes related to discontinued operations recorded net of tax for 2011, 2010 and 2009, which are presented separately in Note 4A.
- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2011 and 2009.

At December 31, 2011, 2010 and 2009, our liability for unrecognized tax benefits was $173 million, $176 million and $160 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $6 million, $8 million and $9 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2011**	2010	2009
Unrecognized tax benefits at beginning of period	**$ 176**	$ 160	$ 104
Gross amounts of increases as a result of tax positions taken in a prior period	**88**	10	11
Gross amounts of decreases as a result of tax positions taken in a prior period	**(24)**	(4)	(3)
Gross amounts of increases as a result of tax positions taken in the current period	**9**	14	52
Gross amounts of decreases as a result of tax positions taken in the current period	**(8)**	(4)	(4)
Amounts of net decreases relating to settlements with taxing authorities	**(68)**	-	-
Unrecognized tax benefits at end of period	**$ 173**	$ 176	$ 160

We and our subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. Our federal tax years are open for examination from 2007 forward, and our open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $25 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our results of operations.

We include interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the net interest (benefit) expense related to unrecognized tax benefits was $(24) million, $9 million and $9 million, respectively, of which a respective $(22) million, $5 million and $5 million (benefit) expense component was deferred as a regulatory asset by PEF, which is amortized as a charge to interest expense over a three-year period or less. During 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009, we accrued $21 million, $45 million and $36 million, respectively, for interest and penalties, which were included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEC

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	2011	2010
Deferred income tax assets		
ARO liability	$ 101	$ 103
Derivative instruments	96	49
Income taxes refundable through future rates	142	142
Pension and other postretirement benefits	244	180
Other	168	158
Tax credit carry forwards	3	-
Net operating loss carry forwards	54	-
Total deferred income tax assets	808	632
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	(1,908)	(1,552)
Income taxes recoverable through future rates	(541)	(421)
Investments	(103)	(104)
Other	(17)	(35)
Total deferred income tax liabilities	(2,569)	(2,112)
Total net deferred income tax liabilities	$ (1,761)	$ (1,480)

The above amounts were classified on the Consolidated Balance Sheets as follows:

(in millions)	2011	2010
Current deferred income tax assets, included in deferred tax assets	$ 142	$ 65
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	(1,903)	(1,545)
Total net deferred income tax liabilities	$ (1,761)	$ (1,480)

At December 31, 2011, PEC had the following tax credit and net operating loss carry forwards:

- $3 million of federal general business credits that will expire during the period 2028 through 2031.
- $161 million of gross federal net operating loss carry forwards that will expire during 2031. $6 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.
- $1 million of gross state net operating loss carry forwards that will expire during the period 2012 through 2030.

Reconciliations of PEC's effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2011	2010	2009
Effective income tax rate	33.2 %	36.8 %	35.0 %
State income taxes, net of federal benefit	(2.3)	(3.2)	(2.8)
Investment tax credit amortization	0.7	0.6	0.7
Domestic manufacturing deduction	-	0.4	0.9
AFUDC equity	2.2	1.5	0.6

Other differences, net	**1.2**	(1.1)	0.6
Statutory federal income tax rate	**35.0 %**	35.0 %	35.0 %

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (27)**	$ 73	$ 192
State	**21**	(8)	21
Total current income tax expense (benefit)	**(6)**	65	213
Deferred			
Federal	**316**	238	57
State	**6**	53	13
Total deferred income tax expense	**322**	291	70
Investment tax credit	**(6)**	(6)	(6)
Net operating loss carry forward	**(54)**	-	-
Total income tax expense	**$ 256**	$ 350	$ 277

Total income tax expense excluded taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Consolidated Statements of Comprehensive Income.

PEC and each of its wholly owned subsidiaries have entered into the Tax Agreement with the Parent (See Note 1D). PEC's intercompany tax receivable was approximately $4 million and $78 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEC's liability for unrecognized tax benefits was $73 million, $74 million and $59 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $4 million and $5 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)	**2011**	2010	2009
Unrecognized tax benefits at beginning of period	**$ 74**	$ 59	$ 38

Gross amounts of increases as a result of tax positions taken in a prior period	**19**	8	6
Gross amounts of decreases as a result of tax positions taken in a prior period	**(14)**	(2)	(2)
Gross amounts of increases as a result of tax positions taken in the current period	**8**	10	17
Gross amounts of decreases as a result of tax positions taken in the current period	**(4)**	(1)	-
Amounts of net decreases relating to settlements with taxing authorities	**(10)**	-	-
Unrecognized tax benefits at end of period	**$ 73**	$ 74	$ 59

We file consolidated federal and state income tax returns that include PEC. In addition, PEC files stand-alone tax returns in various state jurisdictions. PEC's open federal tax years are from 2007 forward, and PEC's open state tax years in our major jurisdictions generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. PEC is not aware of any tax positions for which it is reasonably possible that the total amounts of unrecognized tax benefits will significantly increase or decrease during the 12-month period ending December 31, 2012.

PEC includes interest expense related to unrecognized tax benefits in net interest charges and we include penalties in other, net on the Consolidated Statements of Income. During 2011, 2010 and 2009, the interest (benefit) expense recorded related to unrecognized tax benefits was $(6) million, $4 million and $3 million, respectively. During 2011, 2010 and 2009, there were no penalties related to unrecognized tax benefits. At December 31, 2011, 2010 and 2009, we accrued $8 million, $14 million and $10 million, respectively, for interest and penalties, which were included in interest accrued and other liabilities and deferred credits on the Consolidated Balance Sheets.

PEF

Accumulated deferred income tax assets (liabilities) at December 31 were:

(in millions)	**2011**	2010
Deferred income tax assets		
Derivative instruments	**$ 198**	$ 145
Income taxes refundable through future rates	**198**	93

Pension and other postretirement benefits	**224**	170
Reserve for storm damage	**52**	52
Unbilled revenue	**39**	61
Other	**101**	82
Tax credit carry forwards	**1**	3
Net operating loss carry forwards	**41**	9
Total deferred income tax assets	**854**	615
Deferred income tax liabilities		
Accumulated depreciation and property cost differences	**(1,180)**	(874)
Deferred fuel recovery	**(40)**	(65)
Deferred nuclear cost recovery	**(68)**	(94)
Income taxes recoverable through future rates	**(685)**	(454)
Investments	**(56)**	(60)
Other	**(12)**	(18)
Total deferred income tax liabilities	**(2,041)**	(1,565)
Total net deferred income tax liabilities	**$ (1,187)**	$ (950)

The above amounts were classified on the Balance Sheets as follows:

(in millions)	**2011**	2010
Current deferred income tax assets, included in deferred tax assets	**$ 138**	$ 77
Noncurrent deferred income tax liabilities, included in noncurrent income tax liabilities	**(1,325)**	(1,027)
Total net deferred income tax liabilities	**$ (1,187)**	$ (950)

At December 31, 2011, PEF had the following tax credit and net operating loss carry forwards:

- $1 million of federal general business credits that will expire during the period 2029 through 2031.
- $120 million of gross federal net operating loss carry forwards that will expire during 2031. $3 million of the gross federal net operating loss carry forward is related to excess tax deductions resulting from stock-based compensation plans. The tax benefit from the utilization of this portion of the federal net operating loss carry forward will be recorded as a credit to common stock when realized.

Reconciliations of PEF's effective income tax rate to the statutory federal income tax rate for the years ended December 31 follow:

	2011	2010	2009
Effective income tax rate	**36.3 %**	37.9 %	31.1 %
State income taxes, net of federal benefit	**(3.5)**	(3.2)	(3.0)
Investment tax credit amortization	**0.3**	0.2	0.7
Domestic manufacturing deduction	**-**	-	0.8
AFUDC equity	**1.4**	0.8	3.4
Other differences, net	**0.5**	(0.7)	2.0
Statutory federal income tax rate	**35.0 %**	35.0 %	35.0 %

Income tax expense for the years ended December 31 was comprised of:

(in millions)	**2011**	2010	2009
Current			
Federal	**$ (60)**	$ (44)	$ 125
State	**5**	(4)	20
Total current income tax expense (benefit)	**(55)**	(48)	145
Deferred			
Federal	**255**	293	57
State	**22**	41	11
Total deferred income tax expense	**277**	334	68
Investment tax credit	**(1)**	(1)	(4)
Net operating loss carry forward	**(41)**	(9)	-
Total income tax expense	**$ 180**	$ 276	$ 209

Total income tax expense excluded the following:

- Taxes related to other comprehensive income recorded net of tax for 2011, 2010 and 2009, which are presented separately on the Statements of Comprehensive Income.
- An immaterial amount of current tax benefit, which was recorded in common stock during 2010, related to excess tax deductions resulting from vesting of restricted stock awards, vesting of RSUs, vesting of stock-settled PSSP awards and exercises of nonqualified stock options pursuant to the terms of our EIP. No net current tax benefit was recorded in common stock during 2011 and 2009.

PEF has entered into the Tax Agreement with the Parent (See Note 1D). PEF's intercompany tax receivable was approximately $23 million and $71 million at December 31, 2011 and 2010, respectively.

At December 31, 2011, 2010 and 2009, PEF's liability for unrecognized tax benefits was $80 million, $99 million and $98 million, respectively. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate for income from continuing operations was $1 million, $2 million and $3 million at December 31, 2011, 2010 and 2009, respectively. The following table presents the changes to unrecognized tax benefits during the years ended December 31:

(in millions)		**2011**		2010		2009
Unrecognized tax benefits at beginning of period	**$**	**99**	$	98	$	62
Gross amounts of increases as a result of tax positions taken in a prior period		**66**		2		5
Gross amounts of decreases as a result of tax positions taken in a prior period		**(21)**		(1)		(1)
Gross amounts of increases as a result of tax positions taken in the current period		**1**		3		35
Gross amounts of decreases as a result of tax positions taken in the current period		**(4)**		(3)		(3)
Amounts of net decreases relating to settlements with taxing authorities		**(61)**		-		-
Unrecognized tax benefits at end of period	**$**	**80**	$	99	$	98

We file consolidated federal and state income tax returns that include PEF. PEF's open federal tax years are from 2007 forward, and PEF's open state tax years generally are from 2003 forward. In 2011, the IRS completed its examination of the 2004 and 2005 tax years. It is reasonably possible that unrecognized tax benefits will decrease by approximately $20 million during the 12-month period ending December 31, 2012, due to IRS review of open tax years. Any potential decrease will not have a material impact on our results of operations.

Pursuant to a regulatory order, PEF records interest expense related to unrecognized tax benefits as a regulatory asset, which is amortized over a three-year period or less, with the amortization included in net interest charges on the Statements of Income. Penalties are included in other, net on the Statements of Income. During 2011, 2010 and 2009, interest (benefit) expense recorded as a regulatory asset was $(22) million, $5 million and $5 million, respectively, and there were no penalties recorded related to unrecognized tax benefits. During 2011, PEF charged the unamortized balance of the regulatory asset to interest expense. At December 31, 2011, 2010 and 2009, PEF accrued $7 million, $29 million and $24 million, respectively, for interest and penalties, which were included in prepayments and other current assets and other liabilities and deferred credits on the Balance Sheets.

16. CONTINGENT VALUE OBLIGATIONS

In connection with the acquisition of Florida Progress during 2000, the Parent issued 98.6 million CVOs. Each CVO represents the right of the holder to receive contingent payments based on the performance of four coal-based solid synthetic fuels limited liability companies, three of which were wholly owned (Earthco), purchased by subsidiaries of Florida Progress in October 1999. All of our synthetic fuels businesses were abandoned and all operations ceased as of December 31, 2007 (See Note 4A). The payments are based on the net after-tax cash flows the facilities generated. We make deposits into a CVO trust for estimated contingent payments due to CVO holders based on the results of operations and the utilization of tax credits. The balance of the CVO trust at December 31, 2011 and 2010, was $11 million and is included in other assets and deferred debits on the Consolidated Balance Sheets. Future payments from the trust to CVO holders will not be made until certain conditions are satisfied and will include principal and interest earned during the investment period net of expenses deducted. Interest earned on the payments held in trust for 2011 and 2010 was insignificant.

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us (see Note 22D) related to their ownership of CVOs.

On October 3, 2011, we entered a settlement agreement and release with Davidson Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. In November 2011, we also commenced a tender offer for all remaining outstanding CVOs at the same purchase price. The tender offer expired on February 15, 2012, and as a result, 83.4 million CVOs were repurchased through the settlement agreement or through the tender offer. The CVOs are derivatives and are recorded at fair value. At September 30, 2011, the purchase price included in the settlement agreement and subsequent tender offer represented the fair value of the CVOs. Prior to September 30, 2011, and at December 31, 2011, the CVOs were recorded at fair value based on observable prices from a less-than-active market (see Note 14). A pre-tax loss of $59 million from the changes in fair value during 2011 is recorded in other, net on the Consolidated Statements of Income. At December 31, 2011, the CVO liability included in other current liabilities on our Consolidated Balance Sheets was $14 million based on the 18.5 million outstanding CVOs not held by the Parent. At December 31, 2010, the CVO liability included in other liabilities and deferred credits on our Consolidated Balance Sheets was $15 million based on the 98.6 million CVOs outstanding.

17. BENEFIT PLANS

A. POSTRETIREMENT BENEFITS

We have noncontributory defined benefit retirement plans that provide pension benefits for substantially all full-time employees. We also have supplementary defined benefit pension plans that provide benefits to higher-level employees. In addition to pension benefits, we provide contributory other postretirement benefits (OPEB), including certain health care and life insurance benefits, for retired employees who meet specified criteria. We use a measurement date of December 31 for our pension and OPEB plans.

COSTS OF BENEFIT PLANS

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 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average remaining service period of active participants.

To determine the market-related value of assets, we use a five-year averaging method for a portion of the pension assets and fair value for the remaining portion. We have historically used the five-year averaging method. When we acquired Florida Progress in 2000, we retained the Florida Progress historical use of fair value to determine market-related value for Florida Progress pension assets.

The tables below provide the components of the net periodic benefit cost for the years ended December 31. A portion of net periodic benefit cost is capitalized as part of construction work in progress.

PROGRESS ENERGY

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 53**	$ 48	$ 42	**$ 11**	$ 16	$ 7
Interest cost	**141**	140	138	**41**	45	31
Expected return on plan assets	**(182)**	(157)	(133)	**(2)**	(4)	(4)
Amortization of actuarial loss[(a)]	**69**	51	54	**12**	13	1
Other amortization, net [(a)]	**7**	6	6	**5**	5	5
Net periodic cost before deferral[(b)]	**$ 88**	$ 88	$ 107	**$ 67**	$ 75	$ 40

(a) Adjusted to reflect PEF's rate treatment (See Note 17B).

(b) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

PEC

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 21**	$ 19	$ 18	**$ 5**	$ 5	$ 5
Interest cost	**63**	64	64	**20**	20	16
Expected return on plan assets	**(91)**	(77)	(67)	**-**	(2)	(2)
Amortization of actuarial loss	**26**	16	11	**5**	4	-
Other amortization, net	**5**	6	6	**1**	1	1
Net periodic cost	**$ 24**	$ 28	$ 32	**$ 31**	$ 28	$ 20

PEF

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Service cost	**$ 25**	$ 22	$ 19	**$ 5**	$ 10	$ 2
Interest cost	**59**	59	56	**18**	22	13
Expected return on plan assets	**(78)**	(68)	(56)	**(2)**	(2)	(1)
Amortization of actuarial loss	**33**	31	38	**7**	9	-
Other amortization, net	**-**	-	-	**4**	4	3
Net periodic cost before deferral[a]	**$ 39**	$ 44	$ 57	**$ 32**	$ 43	$ 17

(a) PEF received permission from the FPSC to defer the retail portion of certain 2009 pension expense. The FPSC order did not change the total net periodic pension cost, but deferred a portion of the costs to be recovered in future periods. During 2009, PEF deferred $34 million of net periodic pension costs as a regulatory asset. See Note 8C.

The following tables provide a summary of amounts recognized in other comprehensive income and other comprehensive income reclassification adjustments for amounts included in net income for 2011, 2010 and 2009. The tables also include comparable items that affected regulatory assets. Amounts that would otherwise be recorded in other comprehensive income are recorded as adjustments to regulatory assets consistent with the recovery of the related costs through the ratemaking process.

PROGRESS ENERGY

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Other comprehensive income (loss)						
Recognized for the year						
Net actuarial (loss) gain	**$ (20)**	$ (11)	$ (1)	**$ (2)**	$ (10)	$ 4
Regulatory asset adjustment	**84**	-	-	**(4)**	-	-
Reclassification adjustments						
Net actuarial loss	**10**	4	5	**-**	-	1
Other, net	**2**	-	-	**-**	-	1
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	**(307)**	(65)	10	**(95)**	(164)	64
Reclassification adjustment	**(84)**	-	-	**4**	-	-
Other, net	**-**	-	(3)	**-**	-	-
Amortized to income[a]						
Net actuarial loss	**59**	47	49	**12**	13	-
Other, net	**5**	6	6	**5**	5	4

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

PEC

	Pension Benefits	OPEB

(in millions)	**2011**	2010	2009	**2011**	2010	2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	$ **(134)**	$ (24)	$ (14)	$ **(49)**	$ (64)	$ 38
Other, net	**-**	-	(2)	**-**	-	-
Amortized to income						
Net actuarial loss	**26**	16	11	**5**	4	-
Other, net	**5**	6	6	**1**	1	1

PEF

	Pension Benefits			OPEB		
(in millions)	**2011**	2010	2009	**2011**	2010	2009
Regulatory asset (increase) decrease						
Recognized for the year						
Net actuarial (loss) gain	$ **(147)**	$ (41)	$ 24	$ **(39)**	$ (100)	$ 26
Other, net	**-**	-	(1)	**-**	-	-
Amortized to income[(a)]						
Net actuarial loss	**33**	31	38	**7**	9	-
Other, net	**-**	-	-	**4**	4	3

(a) These amounts were amortized as a component of net periodic cost, as reflected in the previous net periodic cost table. Refer to that table for information regarding the deferral of a portion of net periodic pension cost.

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

	Pension Benefits			OPEB		
	2011	2010	2009	**2011**	2010	2009
Discount rate	**5.60 %**	6.00 %	6.30 %	**5.70 %**	6.05 %	6.20 %
Rate of increase in future compensation						
Bargaining	**4.50 %**	4.50 %	4.25 %	**-**	-	-
Supplementary plans	**5.25 %**	5.25 %	5.25 %	**-**	-	-
Expected long-term rate of return on plan assets	**8.50 %**	8.75 %	8.75 %	**5.00 %**	6.60 %	6.80 %

The weighted-average actuarial assumptions used by PEC and PEF were not materially different from the assumptions above, as applicable, except that the expected long-term rate of return on OPEB plan assets was 5.00% for PEF for all years presented and for PEC was 8.75% for 2010 and 2009. PEC held no OPEB plan assets during 2011.

The expected long-term rates of return on plan assets were determined by considering long-term projected returns based on the plans' target asset allocations. Specifically, return rates were developed for each major asset class and weighted based on the target asset allocations. The projected returns were benchmarked against historical returns for reasonableness. We decreased our expected long-term rate of return on pension assets by 0.25% in 2011, primarily due to a shift in our investment strategy. See the "Assets of Benefit Plans" section below for additional information regarding our investment policies and strategies.

BENEFIT OBLIGATIONS AND ACCRUED COSTS

GAAP requires us to recognize in our statement of financial condition the funded status of our pension and other postretirement benefit plans, measured as the difference between the fair value of the plan assets and the benefit obligation as of the end of the fiscal year.

Reconciliations of the changes in the Progress Registrants' benefit obligations and the funded status as of December 31, 2011 and 2010 are presented in the tables below, with each table followed by related supplementary information.

PROGRESS ENERGY

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Projected benefit obligation at January 1	**$ 2,609**	$ 2,422	**$ 733**	$ 543
Service cost	**53**	48	**11**	16
Interest cost	**141**	140	**41**	45
Settlements	**(6)**	-	**-**	-
Benefit payments	**(129)**	(129)	**(42)**	(44)
Plan amendment	**-**	1	**-**	-
Actuarial loss	**238**	127	**98**	173
Obligation at December 31	**2,906**	2,609	**841**	733
Fair value of plan assets at December 31	**2,191**	1,891	**37**	33
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $2.906 billion and $2.609 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $2.854 billion and $2.563 billion at December 31, 2011 and 2010, respectively, and plan assets of $2.191 billion and $1.891 billion at December 31, 2011 and 2010, respectively.

The accrued benefit costs reflected in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Current liabilities	**$ (10)**	$ (10)	**$ (22)**	$ (22)
Noncurrent liabilities	**(705)**	(708)	**(782)**	(678)
Funded status	**$ (715)**	$ (718)	**$ (804)**	$ (700)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

	Pension Benefits	OPEB

(in millions)	2011	2010	2011	2010
Recognized in accumulated other comprehensive loss				
Net actuarial loss	$ 34	$ 90	$ -	$ 5
Other, net	2	9	-	1
Recognized in regulatory assets, net				
Net actuarial loss	1,139	824	274	183
Other, net	56	55	3	9
Total not yet recognized as a component of net periodic cost[a]	$ 1,231	$ 978	$ 277	$ 198

(a) All components are adjusted to reflect PEF's rate treatment (See Note 17B).

The following table presents the amounts we expect to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss[a]	$ 91	$ 23
Amortization of other, net[a]	9	4

(a) Adjusted to reflect PEF's rate treatment (See Note 17B).

PEC

	Pension Benefits		OPEB	
(in millions)	2011	2010	2011	2010
Projected benefit obligation at January 1	$ 1,188	$ 1,120	$ 352	$ 282
Service cost	21	19	5	5
Interest cost	63	64	20	20
Benefit payments	(56)	(56)	(19)	(19)
Actuarial loss	86	41	49	64
Obligation at December 31	1,302	1,188	407	352
Fair value of plan assets at December 31	1,091	884	-	-
Funded status	$ (211)	$ (304)	$ (407)	$ (352)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.302 billion and $1.188 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.297 billion and $1.184 billion at December 31, 2011 and 2010, respectively, and plan assets of $1.091 billion and $884 million at December 31, 2011 and 2010, respectively.

The accrued benefit costs reflected on the Balance Sheets at December 31 were as follows:

	Pension Benefits		OPEB	
(in millions)	2011	2010	2011	2010

Current liabilities	**$**	**(2)**	$	(2)	**$**	**(19)**	$	(19)
Noncurrent liabilities		**(209)**		(302)		**(388)**		(333)
Funded status	**$**	**(211)**	$	(304)	**$**	**(407)**	$	(352)

The table below provides a summary of amounts not yet recognized as a component of net periodic cost at December 31:

	Pension Benefits				OPEB			
(in millions)		**2011**		2010		**2011**		2010
Recognized in regulatory assets								
Net actuarial loss	**$**	**527**	$	418	**$**	**121**	$	76
Other, net		**43**		49		**-**		2
Total not yet recognized as a component of net periodic cost	**$**	**570**	$	467	**$**	**121**	$	78

The following table presents the amounts PEC expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits		OPEB	
Amortization of actuarial loss	$	37	$	11
Amortization of other, net		8		-

PEF

	Pension Benefits				OPEB			
(in millions)		**2011**		2010		**2011**		2010
Projected benefit obligation at January 1	**$**	**1,087**	$	992	**$**	**326**	$	219
Service cost		**25**		22		**5**		10
Interest cost		**59**		59		**18**		22
Plan amendment		**-**		1		**-**		-
Benefit payments		**(58)**		(58)		**(21)**		(23)
Actuarial loss		**110**		71		**40**		98
Obligation at December 31		**1,223**		1,087		**368**		326
Fair value of plan assets at December 31		**969**		871		**37**		33
Funded status	**$**	**(254)**	$	(216)	**$**	**(331)**	$	(293)

All defined benefit pension plans had accumulated benefit obligations in excess of plan assets, with projected benefit obligations totaling $1.223 billion and $1.087 billion at December 31, 2011 and 2010, respectively. Those plans had accumulated benefit obligations totaling $1.184 billion and $1.049 billion at December 31, 2011 and 2010, respectively, and plan assets of $969 million and $871 million at December 31, 2011 and 2010, respectively.

The accrued benefit costs reflected in the Balance Sheets at December 31 were as follows:

	Pension Benefits				OPEB			
(in millions)		**2011**		2010		**2011**		2010
Current liabilities	**$**	**(3)**	$	(3)	**$**	**-**	$	-
Noncurrent liabilities		**(251)**		(213)		**(331)**		(293)

Funded status	**$ (254)**	$ (216)	**$ (331)**	$ (293)

The following table provides a summary of amounts not yet recognized as a component of net periodic cost at December 31.

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Recognized in regulatory assets, net				
Net actuarial loss	**$ 520**	$ 406	**$ 139**	$ 107
Other, net	**6**	6	**3**	7
Total not yet recognized as a component of net periodic cost	**$ 526**	$ 412	**$ 142**	$ 114

The following table presents the amounts PEF expects to recognize as components of net periodic cost in 2012:

(in millions)	Pension Benefits	OPEB
Amortization of actuarial loss	$ 45	$ 12
Amortization of other, net	-	3

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

	Pension Benefits		OPEB	
	2011	2010	**2011**	2010
Discount rate	**4.75 %**	5.65 %	**4.85 %**	5.75 %
Rate of increase in future compensation				
Bargaining	**4.00 %**	4.50 %	**-**	-
Supplementary plans	**5.25 %**	5.25 %	**-**	-
Initial medical cost trend rate for pre-Medicare Act benefits	**-**	-	**8.75 %**	8.50 %
Initial medical cost trend rate for post-Medicare Act benefits	**-**	-	**8.75 %**	8.50 %
Ultimate medical cost trend rate	**-**	-	**5.00 %**	5.00 %
Year ultimate medical cost trend rate is achieved	**-**	-	**2020**	2017

The weighted-average actuarial assumptions for PEC and PEF were the same or were not significantly different from those indicated above, as applicable. The rates of increase in future compensation include the effects of cost of living adjustments and promotions.

Our primary defined benefit retirement plan for nonbargaining employees is a "cash balance" pension plan. Therefore, we 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.

MEDICAL COST TREND RATE SENSITIVITY

The medical cost trend rates were assumed to decrease gradually from the initial rates to the ultimate rates. The effects of a 1 percent change in the medical cost trend rate are shown below.

	Progress Energy	PEC	PEF
1 percent increase in medical cost trend rate			

Effect on total of service and interest cost	$ 3	$ 1	$ 1
Effect on postretirement benefit obligation	43	21	19
1 percent decrease in medical cost trend rate			
Effect on total of service and interest cost	(2)	(1)	(1)
Effect on postretirement benefit obligation	(31)	(15)	(14)

ASSETS OF BENEFIT PLANS

In the plan asset reconciliation tables that follow, our, PEC's and PEF's employer contributions to qualified plans for 2011 include contributions directly to pension plan assets of $334 million, $217 million and $112 million, respectively, and for 2010 include contributions directly to pension plan assets of $129 million, $95 million and $34 million, respectively. Substantially all of the remaining employer contributions represent benefit payments made directly from the Progress Registrants' assets. The OPEB benefit payments presented in the plan asset reconciliation tables that follow represent the cost after participant contributions. Participant contributions represent approximately 16 percent of gross benefit payments for Progress Energy, 21 percent for PEC and 12 percent for PEF. The OPEB benefit payments are also reduced by prescription drug-related federal subsidies received. In 2011, the subsidies totaled $5 million for us, $2 million for PEC and $2 million for PEF. In 2010, the subsidies totaled $3 million for us, $1 million for PEC and $2 million for PEF.

Reconciliations of the fair value of plan assets at December 31 follow:

PROGRESS ENERGY

	Pension Benefits		OPEB	
(in millions)	**2011**	2010	**2011**	2010
Fair value of plan assets January 1	**$ 1,891**	$ 1,673	**$ 33**	$ 55
Actual return on plan assets	**91**	208	**3**	2

Benefit payments, including settlements		**(135)**		(129)		**(42)**		(44)
Employer contributions		**344**		139		**43**		20
Fair value of plan assets at December 31	**$**	**2,191**	$	1,891	$	**37**	$	33

PEC

	Pension Benefits				OPEB			
(in millions)		**2011**		2010		**2011**		2010
Fair value of plan assets January 1	**$**	**884**	$	749	$	**-**	$	21
Actual return on plan assets		**44**		94		**-**		2
Benefit payments		**(56)**		(56)		**(19)**		(19)
Employer contributions (reimbursements)		**219**		97		**19**		(4)
Fair value of plan assets at December 31	**$**	**1,091**	$	884	$	**-**	$	-

PEF

	Pension Benefits				OPEB			
(in millions)		**2011**		2010		**2011**		2010
Fair value of plan assets January 1	**$**	**871**	$	794	$	**33**	$	32
Actual return on plan assets		**41**		98		**4**		1
Benefit payments		**(58)**		(58)		**(21)**		(23)
Employer contributions		**115**		37		**21**		23
Fair value of plan assets at December 31	**$**	**969**	$	871	$	**37**	$	33

The Progress Registrants' primary objectives when setting investment policies and strategies are to manage the assets of the pension plan to ensure that sufficient funds are available at all times to finance promised benefits and to invest the funds such that contributions are minimized, within acceptable risk limits. We periodically perform studies to analyze various aspects of our pension plans including asset allocations, expected portfolio return, pension contributions and net funded status. One of our key investment objectives is to achieve a rate of return significantly in excess of the discount rate used to measure the plan liabilities over the long term. As of December 31, 2011, the target pension asset allocations are 29 percent domestic equity, 19 percent international equity, 35 percent domestic fixed income, 10 percent private equity and timber and 7 percent absolute return hedge funds. Tactical shifts (plus or minus 5 percent) in asset allocation from the target allocations are made based on the near-term view of the risk and return tradeoffs of the asset classes. Domestic equity includes investments across large, medium and small capitalized domestic stocks, using investment managers with value, growth and core-based investment strategies and includes both long only and long/short equity managers. International equity includes investments in foreign stocks in both developed and emerging market countries, using a mix of value and growth-based investment strategies and includes both long only and long/short equity managers. Domestic fixed income primarily includes domestic investment grade long duration fixed income investments. OPEB plan assets, representing all PEF's OPEB plan assets, are invested in domestic governmental securities.

PROGRESS ENERGY

The following table sets forth by level within the fair value hierarchy our pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	$ 82	$ 33	$ -	$ 115
International equity securities	47	-	-	47
Domestic equity securities	266	-	-	266
Private equity securities	-	-	153	153
Corporate bonds	-	407	-	407
U.S. state and municipal debt	-	42	-	42
U.S. and foreign government debt	247	102	-	349
Commingled funds	-	490	-	490
Hedge funds	-	159	147	306
Timber investments	-	-	11	11
Other investments	-	5	-	5
Fair value of plan assets	$ 642	$ 1,238	$ 311	$ 2,191

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2010				
Assets				
Cash and cash equivalents	$ -	$ 94	$ -	$ 94
International equity securities	40	-	-	40
Domestic equity securities	286	-	-	286
Private equity securities	-	-	147	147
Corporate bonds	-	216	-	216
U.S. state and municipal debt	-	19	-	19
U.S. and foreign government debt	144	30	-	174
Commingled funds	-	847	-	847
Hedge funds	-	51	2	53
Timber investments	-	-	11	11
Other investments	-	4	-	4
Fair value of plan assets	$ 470	$ 1,261	$ 160	$ 1,891

Our other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011, and December 31, 2010, respectively.

A reconciliation of changes in the fair value of our pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	$ 147	$ 2	$ 11	$ 160
Net realized and unrealized gains [a]	-	4	1	5
Transfers in	-	52	-	52
Purchases, sales and distributions, net	6	89	(1)	94
Balance at December 31	$ 153	$ 147	$ 11	$ 311

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 122	$ 2	$ 14	$ 138
Net realized and unrealized gains (losses)[a]	7	-	(2)	5
Purchases, sales and distributions, net	18	-	(1)	17
Balance at December 31	$ 147	$ 2	$ 11	$ 160

(a) Substantially all amounts relate to investments held at December 31.

PEC

The following table sets forth by level within the fair value hierarchy PEC's pension plan assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Total**
2011				
Assets				
Cash and cash equivalents	$ 41	$ 16	$ -	$ 57
International equity securities	24	-	-	24
Domestic equity securities	133	-	-	133
Private equity securities	-	-	76	76
Corporate bonds	-	203	-	203
U.S. state and municipal debt	-	21	-	21
U.S. and foreign government debt	123	51	-	174
Commingled funds	-	244	-	244
Hedge funds	-	79	73	152
Timber investments	-	-	5	5
Other investments	-	2	-	2
Fair value of plan assets	$ 321	$ 616	$ 154	$ 1,091

(in millions)	Pension Benefit Plan Assets Level 1	Level 2	Level 3	Total
2010				
Assets				
Cash and cash equivalents	$ -	$ 44	$ -	$ 44
International equity securities	19	-	-	19
Domestic equity securities	134	-	-	134
Private equity securities	-	-	69	69
Corporate bonds	-	101	-	101
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	67	14	-	81
Commingled funds	-	396	-	396
Hedge funds	-	24	1	25
Timber investments	-	-	5	5
Other investments	-	1	-	1
Fair value of plan assets	$ 220	$ 589	$ 75	$ 884

A reconciliation of changes in the fair value of PEC's pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	**$ 69**	**$ 1**	**$ 5**	**$ 75**
Net realized and unrealized gains[a]	**-**	**2**	**-**	**2**
Transfers in	**-**	**26**	**-**	**26**
Purchases, sales and distributions, net	**7**	**44**	**-**	**51**
Balance at December 31	**$ 76**	**$ 73**	**$ 5**	**$ 154**

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 55	$ 1	$ 6	$ 62
Net realized and unrealized gains (losses)[a]	4	-	(1)	3
Purchases, sales and distributions, net	10	-	-	10
Balance at December 31	$ 69	$ 1	$ 5	$ 75

(a) Substantially all amounts relate to investments held at December 31.

PEF

The following table sets forth by level within the fair value hierarchy PEF's pension assets at December 31, 2011 and 2010. See Note 14 for detailed information regarding the fair value hierarchy.

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
2011				
Assets				
Cash and cash equivalents	**$ 36**	**$ 15**	**$ -**	**$ 51**
International equity securities	**21**	**-**	**-**	**21**
Domestic equity securities	**117**	**-**	**-**	**117**
Private equity securities	**-**	**-**	**68**	**68**
Corporate bonds	**-**	**180**	**-**	**180**
U.S. state and municipal debt	**-**	**19**	**-**	**19**
U.S. and foreign government debt	**109**	**45**	**-**	**154**
Commingled funds	**-**	**217**	**-**	**217**
Hedge funds	**-**	**70**	**65**	**135**
Timber investments	**-**	**-**	**5**	**5**
Other investments	**-**	**2**	**-**	**2**
Fair value of plan assets	**$ 283**	**$ 548**	**$ 138**	**$ 969**

	Pension Benefit Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total
2010				
Assets				
Cash and cash equivalents	$ -	$ 43	$ -	$ 43
International equity securities	18	-	-	18
Domestic equity securities	132	-	-	132
Private equity securities	-	-	68	68
Corporate bonds	-	99	-	99
U.S. state and municipal debt	-	9	-	9
U.S. and foreign government debt	66	14	-	80
Commingled funds	-	391	-	391
Hedge funds	-	23	1	24
Timber investments	-	-	5	5
Other investments	-	2	-	2
Fair value of plan assets	$ 216	$ 581	$ 74	$ 871

PEF's other postretirement benefit plan assets had a fair value of $37 million and $33 million, which consisted of U.S. state and municipal assets classified as Level 2 in the fair value hierarchy at December 31, 2011 and 2010, respectively.

A reconciliation of changes in the fair value of PEF's pension plan assets classified as Level 3 in the fair value hierarchy for the years ended December 31 follows:

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2011				
Balance at January 1	$ 68	$ 1	$ 5	$ 74
Net realized and unrealized gains(a)	-	2	-	2
Transfers in	-	23	-	23
Purchases, sales and distributions, net	-	39	-	39
Balance at December 31	$ 68	$ 65	$ 5	$ 138

(in millions)	Private Equity Securities	Hedge Funds	Timber Investments	Total
2010				
Balance at January 1	$ 58	$ 1	$ 7	$ 66
Net realized and unrealized gains (losses)(a)	3	-	(1)	2
Purchases, sales and distributions, net	7	-	(1)	6
Balance at December 31	$ 68	$ 1	$ 5	$ 74

(a) Substantially all amounts relate to investments held at December 31.

For Progress Energy, PEC and PEF, the determination of the fair values of pension and postretirement plan assets incorporates various factors required under GAAP. The assets of the plan include exchange traded securities (classified within Level 1) and other marketable debt and equity securities, most of which are valued using Level 1 inputs for similar instruments, and are classified within Level 2 investments.

Most over-the-counter investments are valued using observable inputs for similar instruments or prices from similar transactions and are classified as Level 2. Over-the-counter investments where significant unobservable inputs are used, such as financial pricing models, are classified as Level 3 investments.

Investments in private equity are valued using observable inputs, when available, and also include comparable market transactions, income and cost basis valuation techniques. The market approach includes using comparable market transactions or values. The income approach generally consists of the net present value of estimated future cash flows, adjusted as appropriate for liquidity, credit, market and/or other risk factors. Private equity investments are classified as Level 3 investments.

Investments in commingled funds are not publically traded, but the underlying assets held in these funds are traded in active markets and the prices for these assets are readily observable. Holdings in commingled funds are classified as Level 2 investments.

Hedge funds are based primarily on the net asset values and other financial information provided by management of the private investment funds. Hedge funds are classified as Level 2 if the plan is able to redeem the investment with the investee at net asset value as of the measurement date, or at a later date within a reasonable period of time. Hedge funds are classified as Level 3 if the investment cannot be redeemed at net asset value or it cannot be determined when the fund will be redeemed.

Investments in timber are valued primarily on valuations prepared by independent property appraisers. These appraisals are based on cash flow analysis, current market capitalization rates, recent comparable sales transactions, actual sales negotiations and bona fide purchase offers. Inputs include the species, age, volume and condition of timber stands growing on the land; the location, productivity, capacity and accessibility of the timber tracts; current and expected log prices; and current local prices for comparable investments. Timber investments are classified as Level 3 investments.

CONTRIBUTION AND BENEFIT PAYMENT EXPECTATIONS

In 2012, we expect to make contributions of $125 million-$225 million directly to pension plan assets and $1 million of discretionary contributions directly to the OPEB plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $182, $185, $193, $198, $200 and $1,046, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $47, $50, $53, $56, $58 and $318, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from our assets. The benefit payment amounts reflect our net cost after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $4, $5, $5, $6, $7 and $44, respectively.

In 2012, PEC expects to make contributions of $60 million-$110 million directly to pension plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $94, $94, $99, $99, $97 and $479, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $21, $23, $25, $26, $28 and $158, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEC assets. The benefit payment amounts reflect the net cost to PEC after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $3, $3, $3 and $23, respectively.

In 2012, PEF expects to make contributions of $65 million-$115 million directly to pension plan assets and expects to make $1 million of discretionary contributions to OPEB plan assets. The expected benefit payments for the pension benefit plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $64, $67, $70, $73, $76 and $430, respectively. The expected benefit payments for the OPEB plan for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $23, $24, $25, $25, $26 and $137, respectively. The expected benefit payments include benefit payments directly from plan assets and benefit payments directly from PEF's assets. The benefit payment amounts reflect the net cost to PEF after any participant contributions and do not reflect reductions for expected prescription drug-related federal subsidies. The expected federal subsidies for 2012 through 2016 and in total for 2017 through 2021, in millions, are approximately $2, $2, $2, $3, $3 and $17, respectively.

The Patient Protection and Affordable Care Act (PPACA) and the related Health Care and Education Reconciliation Act, which made various amendments to the PPACA, were enacted in March 2010. The PPACA contains a provision that changes the tax treatment related to a federal subsidy available to sponsors of retiree health benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to the benefits under Medicare Part D. The subsidy is known as the Retiree Drug Subsidy. Employers are not currently taxed on the Retiree Drug Subsidy payments they receive. However, as a result of the PPACA as amended, Retiree Drug Subsidy payments will effectively become taxable in tax years beginning after December 31, 2012, by requiring the amount of the subsidy received to be offset against the employer's deduction for health care expenses. Under GAAP, changes in tax law are accounted for in the period of enactment. Accordingly, an additional tax expense of $22 million for us, including $12 million for PEC and $10 million for PEF, was recognized during the year ended December 31, 2010.

B. FLORIDA PROGRESS ACQUISITION

During 2000, we completed our acquisition of Florida Progress. Florida Progress' pension and OPEB liabilities, assets and net periodic costs are reflected in the above information as appropriate. Certain of Florida Progress' nonbargaining unit benefit plans were merged with our benefit plans effective January 1, 2002.

PEF continues to recover qualified plan pension costs and OPEB costs in rates as if the acquisition had not occurred. The information presented in Note 17A is adjusted as appropriate to reflect PEF's rate treatment.

18. RISK MANAGEMENT ACTIVITIES AND DERIVATIVE TRANSACTIONS

We are exposed to various risks related to changes in market conditions. We have a risk management committee that includes senior executives from various business groups. The risk management committee is responsible for administering risk management policies and monitoring compliance with those policies by all subsidiaries. Under our risk policy, we 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. We minimize such risk by performing credit and financial reviews using a combination of financial analysis and publicly available credit ratings of such counterparties. Potential nonperformance by counterparties is not expected to have a material effect on our financial position or results of operations.

See Note 14B for information about the fair value of derivatives.

A. COMMODITY DERIVATIVES

GENERAL

Most of our physical commodity contracts are not derivatives or qualify as normal purchases or sales. Therefore, such contracts are not recorded at fair value.

ECONOMIC DERIVATIVES

Derivative products, primarily natural gas and oil contracts, may be entered into from time to time for economic hedging purposes. While management believes the economic hedges 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 Utilities have financial derivative instruments with settlement dates through 2015 related to their exposure to price fluctuations on fuel oil and natural gas purchases. The majority of our financial hedge agreements will settle in 2012 and 2013. Substantially all of these instruments receive regulatory accounting treatment. Related unrealized gains and losses are recorded in regulatory liabilities and regulatory assets, respectively, on the Balance Sheets until the contracts are settled (See Note 8A). After settlement of the derivatives and the fuel is consumed, any realized gains or losses are passed through the fuel cost-recovery clause.

Certain hedge agreements may result in the receipt of, or posting of, derivative collateral with our counterparties, depending on the daily derivative position. Fluctuations in commodity prices that lead to our return of collateral received and/or our posting of collateral with our counterparties negatively impact our liquidity. We manage open positions with strict policies that limit our exposure to market risk and require daily reporting to management of potential financial exposures.

Certain counterparties have posted or held cash collateral in support of these instruments. Progress Energy had a cash collateral asset included in derivative collateral posted of $147 million and $164 million on the Progress Energy Consolidated Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, Progress Energy had 380.0 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

PEC had a cash collateral asset included in prepayments and other current assets of $24 million on the PEC Consolidated Balance Sheets at December 31, 2011 and 2010. At December 31, 2011, PEC had 111.4 million MMBtu notional of natural gas related to outstanding commodity derivative swaps that were entered into to hedge forecasted natural gas purchases.

PEF's cash collateral asset included in derivative collateral posted was $123 million and $140 million on the PEF Balance Sheets at December 31, 2011 and 2010, respectively. At December 31, 2011, PEF had 268.6 million MMBtu notional of natural gas and 10.3 million gallons notional of oil related to outstanding commodity derivative swaps and options that were entered into to hedge forecasted natural gas and oil purchases.

B. INTEREST RATE DERIVATIVES – FAIR VALUE OR CASH FLOW HEDGES

We use cash flow hedging strategies to reduce exposure to changes in cash flow due to fluctuating interest rates. We use fair value hedging strategies to reduce exposure to changes in fair value due to interest rate changes. Our cash flow hedging strategies are primarily accomplished through the use of forward starting swaps, and our fair value hedging strategies are primarily accomplished through the use of fixed-to-floating swaps. The notional amounts of interest rate derivatives are not exchanged and do not represent exposure to credit loss. In the event of default by the counterparty, the exposure in these transactions is the cost of replacing the agreements at current market rates.

CASH FLOW HEDGES

At December 31, 2011, all open interest rate hedges will reach their mandatory termination dates within two years. At December 31, 2011, including amounts related to terminated hedges, we had $141 million of after-tax losses, including $71 million and $25 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive loss related to forward starting swaps. It is expected that in the next 12 months losses of $12 million, net of tax, primarily related to terminated hedges, will be reclassified to interest expense at Progress Energy, including $6 million and $2 million at PEC and PEF, respectively. The actual amounts that will be reclassified to earnings may vary from the expected amounts as a result of changes in interest rates, changes in the timing of debt issuances at the Parent and the Utilities and changes in market value of currently open forward starting swaps.

At December 31, 2010, including amounts related to terminated hedges, we had $63 million of after-tax losses, including $33 million and $4 million of after-tax losses at PEC and PEF, respectively, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2009, including amounts related to terminated hedges, we had $35 million of after-tax losses, including $27 million of after-tax losses at PEC and $3 million of after-tax gains at PEF, recorded in accumulated other comprehensive income related to forward starting swaps.

At December 31, 2011, Progress Energy had $500 million notional of open forward starting swaps, including $250 million at PEC and $50 million at PEF.

At December 31, 2010, Progress Energy had $1.050 billion notional of open forward starting swaps, including $350 million at PEC and $200 million at PEF.

FAIR VALUE HEDGES

For interest rate fair value hedges, the change in the fair value of the hedging derivative is recorded in net interest charges and is offset by the change in the fair value of the hedged item. At December 31, 2011 and 2010, neither we nor the Utilities had any outstanding positions in such contracts.

C. CONTINGENT FEATURES

Certain of our commodity derivative instruments contain provisions defining fair value thresholds requiring the posting of collateral for hedges in a liability position greater than such threshold amounts. The thresholds are tiered and based on the individual company's credit rating with Moody's, S&P and/or Fitch Ratings (Fitch). Higher credit ratings have a higher threshold requiring a lower amount of the outstanding liability position to be covered by posted collateral. Conversely, lower credit ratings require a higher amount of the outstanding liability position to be covered by posted collateral. If our credit ratings were to be downgraded, we may have to post additional collateral on certain hedges in liability positions.

In addition, certain of our commodity derivative instruments contain provisions that require our debt to maintain an investment grade credit rating from Moody's, S&P and/or Fitch. If our debt were to fall below investment grade, we would be in violation of these provisions, and the counterparties to the commodity derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on commodity derivative instruments in net liability positions.

The aggregate fair value of all commodity derivative instruments at Progress Energy with credit risk-related contingent features that are in a net liability position was $489 million at December 31, 2011, for which Progress Energy has posted collateral of $147 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, Progress Energy would have been required to post an additional $342 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEC with credit risk-related contingent features that are in a liability position was $152 million at December 31, 2011, for which PEC has posted collateral of $24 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered at December 31, 2011, PEC would have been required to post an additional $128 million of collateral with its counterparties.

The aggregate fair value of all commodity derivative instruments at PEF with credit risk-related contingent features that are in a net liability position was $337 million at December 31, 2011, for which PEF has posted collateral of $123 million in the normal course of business. If the credit risk-related contingent features underlying these agreements had been triggered on December 31, 2011, PEF would have been required to post an additional $214 million of collateral with its counterparties.

D. DERIVATIVE INSTRUMENT AND HEDGING ACTIVITY INFORMATION

PROGRESS ENERGY

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location (in millions)	2011 Asset	2011 Liability	2010 Asset	2010 Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		$ 2		$ -
Derivative liabilities, long-term		1		-
Interest rate derivatives				
Prepayments and other current assets	$ -		$ 1	
Other assets and deferred debits	-		3	
Derivative liabilities, current		76		32
Derivative liabilities, long-term		17		7
Total derivatives designated as hedging instruments	-	96	4	39
Derivatives not designated as hedging instruments				
Commodity derivatives(a)				
Prepayments and other current assets	5		11	
Other assets and deferred debits	-		4	
Derivative liabilities, current		357		226
Derivative liabilities, long-term		332		268
CVOs(b)				
Other current liabilities		14		-
Other liabilities and deferred credits		-		15
Fair value of derivatives not designated as hedging instruments	5	703	15	509
Fair value loss transition adjustment(c)				
Derivative liabilities, current		1		1
Derivative liabilities, long-term		2		3
Total derivatives not designated as hedging instruments	5	706	15	513
Total derivatives	$ 5	$ 802	$ 19	$ 552

(a) Substantially all of these contracts receive regulatory treatment.

(b) The Parent issued 98.6 million CVOs in connection with the acquisition of Florida Progress during 2000. In 2011, we purchased 80.1 million CVOs in a negotiated settlement agreement and subsequent tender offer. (See Note 16)

(c) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contracts.

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive Income and the Consolidated Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[c]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[d] [e]	**(85)**	(34)	15	**(8)**	(6)	(6)	**(3)**	3	(3)
Total	**$ (87)**	$ (34)	$ 16	**$ (8)**	$ (6)	$ (6)	**$ (3)**	$ 3	$ (3)

(a) Effective portion.

(b) Related to ineffective portion and amount excluded from effectiveness testing.

(c) Amounts recorded on the Consolidated Statements of Income are classified in fuel used in electric generation.

(d) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

(e) Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
	2011	2010	2009	**2011**	2010	2009
Commodity derivatives[a]	**$ (297)**	$ (324)	$ (659)	**$ (502)**	$ (398)	$ (387)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.

(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives		
	2011	2010	2009
Commodity derivatives[a]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[a]	**1**	1	2
CVOs[a]	**(59)**	-	19
Total	**$ (58)**	$ 1	$ 22

(a) Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEC

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location	2011		2010	
(in millions)	Asset	Liability	Asset	Liability
Derivatives designated as hedging instruments				
Interest rate derivatives				
Other assets and deferred debits	$ -		$ 3	
Derivative liabilities, current		$ 38		$ 7
Other liabilities and deferred credits		9		4
Total derivatives designated as hedging instruments	-	47	3	11
Derivatives not designated as hedging instruments				
Commodity derivatives[(a)]				
Prepayments and other current assets	-		1	
Other assets and deferred debits	-		1	
Derivative liabilities, current		91		45
Other liabilities and deferred credits		110		78
Fair value of derivatives not designated as hedging instruments	-	201	2	123
Fair value loss transition adjustment[(b)]				
Derivative liabilities, current		1		1
Other liabilities and deferred credits		2		3
Total derivatives not designated as hedging instruments	-	204	2	127
Total derivatives	$ -	$ 251	$ 5	$ 138

(a) Substantially all of these contracts receive regulatory treatment.

(b) In 2003, PEC recorded a $38 million pre-tax ($23 million after-tax) fair value loss transition adjustment pursuant to the adoption of new accounting guidance for derivatives. The related liability is being amortized to earnings over the term of the related contracts.

The following tables present the effect of derivative instruments on the Consolidated Statements of Comprehensive

Income and the Consolidated Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Interest rate derivatives[c] [d]	**$ (43)**	$ (10)	$ 5	**$ (5)**	$ (4)	$ (3)	**$ (1)**	$ -	$ (2)

(a) Effective portion.

(b) Related to ineffective portion and amount excluded from effectiveness testing.

(c) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.

(d) Amounts recorded on the Consolidated Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
	2011	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (60)**	$ (46)	$ (76)	**$ (140)**	$ (77)	$ (68)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.

(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Consolidated Balance Sheets until derivatives are settled.

Instrument (in millions)	Amount of Gain or (Loss) Recognized in Income on Derivatives		
	2011	2010	2009
Commodity derivatives[a]	**$ -**	$ -	$ 1
Fair value loss transition adjustment[a]	**1**	1	2
Total	**$ 1**	$ 1	$ 3

(a) Amounts recorded on the Consolidated Statements of Income are classified in other, net.

PEF

The following table presents the fair value of derivative instruments at December 31:

Instrument / Balance sheet location (in millions)	2011 Asset	2011 Liability	2010 Asset	2010 Liability
Derivatives designated as hedging instruments				
Commodity cash flow derivatives				
Derivative liabilities, current		$ 2		$ -
Derivative liabilities, long-term		1		-
Interest rate derivatives				
Derivative liabilities, current		-		7
Derivative liabilities, long-term		8		-
Total derivatives designated as hedging instruments		11		7
Derivatives not designated as hedging instruments				
Commodity derivatives[a]				
Prepayments and other current assets	$ 5		$ 10	
Other assets and deferred debits	-		3	
Derivative liabilities, current		266		181
Derivative liabilities, long-term		222		190
Total derivatives not designated as hedging instruments	5	488	13	371
Total derivatives	$ 5	$ 499	$ 13	$ 378

(a) Substantially all of these contracts receive regulatory treatment.

The following tables present the effect of derivative instruments on the Statements of Comprehensive Income and the Statements of Income for the years ended December 31:

Derivatives Designated as Hedging Instruments

Instrument (in millions)	Amount of Gain or (Loss) Recognized in OCI, Net of Tax on Derivatives[a]			Amount of Gain or (Loss), Net of Tax Reclassified from Accumulated OCI into Income[a]			Amount of Pre-tax Gain or (Loss) Recognized in Income on Derivatives[b]		
	2011	2010	2009	**2011**	2010	2009	**2011**	2010	2009
Commodity cash flow derivatives[c]	**$ (2)**	$ -	$ 1	**$ -**	$ -	$ -	**$ -**	$ -	$ -
Interest rate derivatives[d] [e]	**(21)**	(7)	3	**-**	-	-	**-**	-	-
Total	**$ (23)**	$ (7)	$ 4	**$ -**	$ -	$ -	**$ -**	$ -	$ -

(a) Effective portion.
(b) Related to ineffective portion and amount excluded from effectiveness testing.
(c) Amounts recorded on the Statements of Income are classified in fuel used in electric generation.
(d) Amounts in accumulated OCI related to terminated hedges are reclassified to earnings as the interest expense is recorded. The effective portion of the hedges will be amortized to interest expense over the term of the related debt.
(e) Amounts recorded on the Statements of Income are classified in interest charges.

Derivatives Not Designated as Hedging Instruments

Instrument (in millions)	Realized Gain or (Loss)[a]			Unrealized Gain or (Loss)[b]		
	2011	2010	2009	**2011**	2010	2009
Commodity derivatives	**$ (237)**	$ (278)	$ (583)	**$ (362)**	$ (321)	$ (319)

(a) After settlement of the derivatives and the fuel is consumed, gains or losses are passed through the fuel cost-recovery clause.
(b) Amounts are recorded in regulatory liabilities and assets, respectively, on the Balance Sheets until derivatives are settled.

19. RELATED PARTY TRANSACTIONS

There were no material related party transactions in which we or any of our subsidiaries were or will be a participant and in which any of our directors, executive officers or any of their immediate family members had a direct or indirect material interest. Transactions between affiliated companies are further discussed below.

As a part of normal business, we 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. Our guarantees may include performance obligations under power supply agreements, transmission agreements, gas agreements, fuel procurement agreements, trading operations and cash management. Our guarantees also include standby letters of credit and surety bonds. At December 31, 2011, the Parent had issued $453 million of guarantees for future financial or performance assurance on behalf of its subsidiaries. This includes $300 million of guarantees of certain payments of two wholly owned indirect subsidiaries (See Note 23). We do not believe conditions are likely for significant performance under the guarantees of performance issued by or on behalf of affiliates. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the Consolidated Balance Sheets.

Our subsidiaries provide and receive services, at cost, to and from the Parent and its subsidiaries, in accordance with agreements approved by the SEC pursuant to Section 13(b) of the Public Utility Holding Company Act of 1935. The repeal of the Public Utility Holding Company Act of 1935 effective February 8, 2006, and subsequent regulation by the FERC did not change our current intercompany services. Services include purchasing, human resources, accounting, legal, transmission and delivery support, engineering materials, contract support, loaned employees payroll costs, construction 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 that 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 Balance Sheets.

PESC provides the majority of the affiliated goods and services under the approved agreements. Goods and services provided by PESC during 2011, 2010 and 2009 to PEC amounted to $203 million, $176 million and $170 million, respectively, and services provided to PEF were $160 million, $156 million and $147 million, respectively. During 2010, PESC transferred a $24 million combustion turbine to PEC at cost.

PEC and PEF also provide and receive goods and services at cost. Goods and services provided by PEC to PEF during 2011, 2010 and 2009 amounted to $57 million, $43 million and $36 million, respectively. Goods and services provided by PEF to PEC during 2011, 2010 and 2009 amounted to $12 million, $18 million and $12 million, respectively.

PEC and PEF participate in an internal money pool, administered by PESC, to more effectively utilize cash resources and to reduce outside short-term borrowings. The money pool is also used to settle intercompany balances. The weighted-average interest rate for the money pool was 0.32%, 0.30% and 0.74% for the years ended December 31, 2011, 2010 and 2009, respectively. Amounts payable to the money pool are included in notes payable to affiliated companies on the Balance Sheets. PEC and PEF recorded minimal interest expense related to the money pool for all the years presented.

PEC and each of its wholly owned subsidiaries and PEF have entered into the Tax Agreement with the Parent (See Note 15).

20. FINANCIAL INFORMATION BY BUSINESS SEGMENT

Our reportable segments are PEC and PEF, both of which are primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina and in portions of Florida, respectively. These electric operations also distribute and sell electricity to other utilities, primarily on the east coast of the United States.

In addition to the reportable operating segments, the Corporate and Other segment includes the operations of the Parent and PESC and other miscellaneous nonregulated businesses that do not separately meet the quantitative thresholds for disclosure as separate reportable business segments.

Products and services are sold between the various reportable segments. All intersegment transactions are at cost.

In the following tables, capital and investment expenditures include property additions, acquisitions of nuclear fuel and other capital investments.

(in millions)	PEC	PEF	Corporate and Other	Eliminations	Total
At and for the year ended December 31, 2011					
Revenues					
Unaffiliated	**$ 4,528**	**$ 4,367**	**$ 12**	**$ -**	**$ 8,907**
Intersegment	**-**	**2**	**272**	**(274)**	**-**
Total revenues	**4,528**	**4,369**	**284**	**(274)**	**8,907**
Depreciation, amortization and accretion	**514**	**169**	**18**	**-**	**701**
Interest income	**1**	**1**	**22**	**(22)**	**2**
Total interest charges, net	**184**	**239**	**324**	**(22)**	**725**
Income tax expense (benefit)[(a)]	**268**	**311**	**(99)**	**-**	**480**
Ongoing Earnings	**541**	**530**	**(200)**	**-**	**871**
Total assets	**16,102**	**14,484**	**20,926**	**(16,453)**	**35,059**
Capital and investment expenditures	**1,423**	**710**	**17**	**-**	**2,150**
At and for the year ended December 31, 2010					
Revenues					
Unaffiliated	$ 4,922	$ 5,252	$ 16	$ -	$ 10,190
Intersegment	-	2	248	(250)	-
Total revenues	4,922	5,254	264	(250)	10,190
Depreciation, amortization and accretion	479	426	15	-	920
Interest income	3	1	31	(28)	7
Total interest charges, net	186	258	331	(28)	747
Income tax expense (benefit)[(a)]	342	267	(87)	-	522
Ongoing Earnings	618	462	(191)	-	889
Total assets	14,899	14,056	21,110	(17,011)	33,054
Capital and investment expenditures	1,382	991	33	(24)	2,382

At and for the year ended December 31, 2009

Revenues

Unaffiliated	$ 4,627	$ 5,249	$ 9	$ -	$ 9,885
Intersegment	-	2	234	(236)	-
Total revenues	4,627	5,251	243	(236)	9,885
Depreciation, amortization and accretion	470	502	14	-	986
Interest income	5	4	38	(33)	14
Total interest charges, net	195	231	286	(33)	679
Income tax expense (benefit)(a)	295	209	(88)	-	416
Ongoing Earnings	540	460	(154)	-	846
Total assets	13,502	13,100	20,538	(15,904)	31,236
Capital and investment expenditures	962	1,532	21	(12)	2,503

(a) Income tax expense (benefit) excludes the tax impact of Ongoing Earnings adjustments.

Management uses the non-GAAP financial measure "Ongoing Earnings" as a performance measure to evaluate the results of our segments and operations. Ongoing Earnings as presented here may not be comparable to similarly titled measures used by other companies. Ongoing Earnings is computed as GAAP net income attributable to controlling interests less discontinued operations and the effects of certain identified gains and charges, which are considered Ongoing Earnings adjustments. Some of the excluded gains and charges have occurred in more than one reporting period but are not considered representative of fundamental core earnings. Management has identified the following Ongoing Earnings adjustments: CVO mark-to-market adjustments because we are unable to predict changes in their fair value; CR3 indemnification charge (and subsequent adjustments, if any) for estimated future years' joint owner replacement power costs (through the expiration of the indemnification provisions of the joint owner agreement) because GAAP requires that the charge be accounted for in the period in which it becomes probable and estimable rather than the periods to which it relates; and the impact from changes in the tax treatment of the Medicare Part D subsidy because GAAP requires that the impact of the tax law change be accounted for in the period of enactment rather than the affected tax year. Additionally, management does not consider impairments, charges (and subsequent adjustments, if any) recognized for the retirement of generating units prior to the end of their estimated useful lives, merger and integration costs, cumulative prior period adjustments, operating results of discontinued operations and the amount to be refunded to customers through the fuel clause included in the terms of the 2012 settlement agreement to be representative of our ongoing operations and excluded these items in computing Ongoing Earnings.

Reconciliations of consolidated Ongoing Earnings to net income attributable to controlling interests for the years ended December 31 follow:

(in millions)	**2011**	2010	2009

Ongoing Earnings	**$**	**871**	$	889	$	846
CVO mark-to-market, net of tax benefit of $14 and $- (Note 16)		**(45)**		-		19
Impairment, net of tax benefit of $1, $4 and $1		**(2)**		(6)		(2)
Merger and integration costs, net of tax benefit of $17 (Note 2)		**(46)**		-		-
CR3 indemnification charge, net of tax benefit of $13 (Note 22C)		**(20)**		-		-
Plant retirement charge, net of tax benefit of $1, $1 and $11		**(1)**		(1)		(17)
Amount to be refunded to customers, net of tax benefit of $111 (Note 8C)		**(177)**		-		-
Change in tax treatment of the Medicare Part D subsidy (Note 17)		-		(22)		-
Cumulative prior period adjustment related to certain employee life insurance benefits, net of tax benefit of $7		-		-		(10)
Continuing income attributable to noncontrolling interests, net of tax		**7**		7		4
Income from continuing operations		**587**		867		840
Discontinued operations, net of tax		**(5)**		(4)		(79)
Net income attributable to noncontrolling interests, net of tax		**(7)**		(7)		(4)
Net income attributable to controlling interests	**$**	**575**	$	856	$	757

21. ENVIRONMENTAL MATTERS

We are subject to regulation by various federal, state and local authorities in the areas of air quality, water quality, control of toxic substances and hazardous and solid wastes, and other environmental matters. We believe that we are in substantial compliance with those environmental regulations currently applicable to our business and operations and believe we have all necessary permits to conduct such operations. Environmental laws and regulations frequently change and the ultimate costs of compliance cannot always be precisely estimated.

A. HAZARDOUS AND SOLID WASTE

The U.S. Environmental Protection Agency (EPA) and a number of states are considering additional regulatory measures that may affect management, treatment, marketing and disposal of coal combustion residuals, primarily ash, from each of the Utilities' coal-fired plants. Revised or new laws or regulations under consideration may impose changes in solid waste classifications or groundwater protection environmental controls. In June 2010, the EPA proposed two options for new rules to regulate coal combustion residuals. The first option would create a comprehensive program of federally enforceable requirements for coal combustion residuals management and disposal under federal hazardous waste rules. The other option would have the EPA set design and performance standards for coal combustion residuals management facilities and regulate disposal of coal combustion residuals as nonhazardous waste with enforcement by the courts or state laws. The EPA did not identify a preferred option. Under both options, the EPA may leave in place a regulatory exemption for approved beneficial uses of coal combustion residuals that are recycled. A final rule is expected in late 2012. Compliance plans and estimated costs to meet the requirements of new regulations will be determined when any new regulations are finalized. We are also evaluating the effect on groundwater quality from past and current operations, which may result in operational changes and additional measures under existing regulations. These issues are also under evaluation by state agencies. Certain regulated chemicals have been measured in wells near our ash ponds at levels above groundwater quality standards. Additional monitoring and investigation will be conducted. Detailed plans and cost estimates will be determined if these evaluations reveal that corrective actions are necessary. We cannot predict the outcome of this matter.

The provisions of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), authorize the EPA to require the cleanup of hazardous waste sites. This statute imposes retroactive joint and several liabilities. Some states, including North Carolina, South Carolina and Florida, have similar types of statutes. We are periodically notified by regulators, including the EPA and various state agencies, of our involvement or potential involvement in sites that may require investigation and/or remediation. There are presently several sites with respect to which we have been notified of our potential liability by the EPA, the state of North Carolina, the state of Florida, or potentially responsible party (PRP) groups as described below in greater detail. Various organic materials associated with the production of manufactured gas, generally referred to as coal tar, are regulated under federal and state laws. PEC and PEF are each PRPs at several manufactured gas plant (MGP) sites. We are also currently in the process of assessing potential costs and exposures at other sites. These costs are eligible for regulatory recovery through either base rates or cost-recovery clauses. Both PEC and PEF evaluate potential claims against other PRPs and insurance carriers and plan to submit claims for cost recovery where appropriate. The outcome of potential and pending claims cannot be predicted.

We measure our liability for environmental sites based on available evidence, including our experience in investigating and remediating environmentally impaired sites. The process often involves assessing and developing cost-sharing arrangements with other PRPs. For all sites, as assessments are developed and analyzed, we will accrue costs for the sites in O&M expense on the Income Statements to the extent our liability is probable and the costs can be reasonably estimated. 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 reached the stage where a reasonable estimate of the remediation costs can be made, we cannot determine the total costs that may be incurred in connection with the remediation of all sites at this time. It is probable that current estimates will change and additional losses, which could be material, may be incurred in the future.

The following tables contain information about accruals for probable and estimable costs related to various environmental sites, which are included in other current liabilities and other liabilities and deferred credits on the Balance Sheets:

PROGRESS ENERGY

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2008	**$ 31**	**$ 22**	**$ 53**
Amount accrued for environmental loss contingencies	3	13	16
Expenditures for environmental loss contingencies	(12)	(15)	(27)
Balance, December 31, 2009[(a)]	**22**	**20**	**42**
Amount accrued for environmental loss contingencies	8	13	21
Expenditures for environmental loss contingencies	(10)	(18)	(28)
Balance, December 31, 2010[(a)]	**20**	**15**	**35**
Amount accrued for environmental loss contingencies	**2**	**8**	**10**
Expenditures for environmental loss contingencies	**(5)**	**(17)**	**(22)**
Balance, December 31, 2011[(a)]	**$ 17**	**$ 6**	**$ 23**

(a) Expected to be paid out over one to 15 years.

PEC

(in millions)	MGP and Other Sites

Balance, December 31, 2008	**$**	**16**
Amount accrued for environmental loss contingencies		3
Expenditures for environmental loss contingencies		(6)
Balance, December 31, 2009(a)		**13**
Amount accrued for environmental loss contingencies		3
Expenditures for environmental loss contingencies		(4)
Balance, December 31, 2010(a)		**12**
Amount accrued for environmental loss contingencies		**1**
Expenditures for environmental loss contingencies		**(2)**
Balance, December 31, 2011(a)	**$**	**11**

(a) Expected to be paid out over one to five years.

PEF

(in millions)	MGP and Other Sites	Remediation of Distribution and Substation Transformers	Total
Balance, December 31, 2008	**$ 15**	**$ 22**	**$ 37**
Amount accrued for environmental loss contingencies	**-**	**13**	**13**
Expenditures for environmental loss contingencies	**(6)**	**(15)**	**(21)**
Balance, December 31, 2009(a)	**9**	**20**	**29**
Amount accrued for environmental loss contingencies	5	13	18
Expenditures for environmental loss contingencies	(6)	(18)	(24)
Balance, December 31, 2010(a)	**8**	**15**	**23**
Amount accrued for environmental loss contingencies	**1**	**8**	**9**
Expenditures for environmental loss contingencies	**(3)**	**(17)**	**(20)**
Balance, December 31, 2011(a)	**$ 6**	**$ 6**	**$ 12**

(a) Expected to be paid out over one to 15 years.

PROGRESS ENERGY

In addition to the Utilities' sites discussed under "PEC" and "PEF" below, we incurred indemnity obligations related to certain pre-closing liabilities of divested subsidiaries, including certain environmental matters (See discussion under Guarantees in Note 22C).

PEC

PEC has recorded a minimum estimated total remediation cost for all of its remaining MGP sites based upon its historical experience with remediation of several of its MGP sites. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

In 2004, the EPA advised PEC that it had been identified as a PRP at the Ward Transformer site located in Raleigh, N.C. (Ward) site. The EPA offered PEC and a number of other PRPs the opportunity to negotiate the removal action for the Ward site and reimbursement to the EPA for the EPA's past expenditures in addressing conditions at the Ward site. Subsequently, PEC and other

PRPs signed a settlement agreement, which requires the participating PRPs to remediate the Ward site. At December 31, 2011 and December 31, 2010, PEC's recorded liability for the site was approximately $5 million. In 2008 and 2009, PEC filed civil actions against PRPs seeking contribution for and recovery of costs incurred in remediating the Ward site, as well as a declaratory judgment that defendants are jointly and severally liable for response costs at the site. PEC has settled with a number of the PRPs and is in active settlement negotiations with others. On March 24, 2010, the federal district court in which this matter is pending denied motions to dismiss filed by a number of defendants, but granted several other motions filed by state agencies and successor entities. The court established a "test case" program providing for a determination of liability on the part of a set of representative defendants. Summary judgment motions and responsive pleadings are being filed by and against these defendants and discovery and briefing will be completed by May 2012. Meanwhile, proceedings with respect to the other defendants have been stayed. The outcome of these matters cannot be predicted.

In 2008, the EPA issued a Record of Decision for the operable unit for stream segments downstream from the Ward site (Ward OU1) and advised 61 parties, including PEC, of their identification as PRPs for Ward OU1 and for further investigation at the Ward facility and certain adjacent areas (Ward OU2). The EPA's estimate for the selected remedy for Ward OU1 is approximately $6 million. The EPA offered PEC and the other PRPs the opportunity to negotiate implementation of a response action for Ward OU1 and a remedial investigation and feasibility study for Ward OU2, as well as reimbursement to the EPA of approximately $1 million for the EPA's past expenditures in addressing conditions at the site. On September 29, 2011, the EPA issued unilateral administrative orders to certain parties, which did not include PEC, directing the performance of remedial activities with regard to Ward OU1. It is not possible at this time to reasonably estimate the total amount of PEC's obligation, if any, for Ward OU1 and Ward OU2.

PEF

The accruals for PEF's MGP and other sites relate to two former MGP sites and other sites associated with PEF that have required, or are anticipated to require, investigation and/or remediation. The maximum amount of the range for all the sites cannot be determined at this time. Actual experience may differ from current estimates, and it is probable that estimates will continue to change in the future.

PEF has received approval from the FPSC for recovery through the ECRC of the majority of costs associated with the remediation of distribution and substation transformers. Under agreements with the Florida Department of Environmental Protection (FDEP), PEF has reviewed all distribution transformer sites and all substation sites for mineral oil-impacted soil caused by equipment integrity issues. Should additional distribution transformer sites be identified outside of this population, the distribution O&M costs will not be recoverable through the ECRC.

B. AIR AND WATER QUALITY

We are, or may ultimately be, subject to various current and proposed federal, state and local environmental compliance laws and regulations impacting air and water quality, which likely would result in increased capital expenditures and O&M expense. Control equipment installed for compliance with then-existing or proposed laws and regulations may address some of the issues outlined. PEC and PEF have been developing an integrated compliance strategy to meet these evolving requirements. PEC has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the North Carolina Clean Smokestacks Act (Clean Smokestacks Act). The air quality controls installed to comply with nitrogen oxides (NOx) and sulfur dioxide (SO_2) requirements under certain sections of the Clean Air Act and the Clean Smokestacks Act, as well as PEC's plan to replace a portion of its coal-fired generation with natural gas-fueled generation, largely address the CAIR requirements for NOx and SO_2 for our North Carolina units at PEC. PEF has installed environmental compliance controls that meet the emission reduction requirements under the first phase of the CAIR.

In 2008, the D.C. Court of Appeals vacated the Clean Air Mercury Rule (CAMR). As a result, the EPA subsequently announced that it would develop maximum achievable control technology (MACT) standards. The U.S. District Court for the District of Columbia issued an order requiring the EPA to issue a final MACT standard for power plants. On February 16, 2012, the EPA published the final MACT standards for coal-fired and oil-fired electric steam generating units (EGU MACT). The rule will become effective on April 16, 2012. Compliance is due in three years with provisions for a one-year extension from state agencies on a case-by-case basis. The EGU

MACT contains stringent emission limits for mercury, non-mercury metals and acid gases from coal-fired units and hazardous air pollutant metals, acid gases and hydrogen fluoride from oil-fired units. The North Carolina mercury rule contains a requirement that all coal-fired units in the state install mercury controls by December 31, 2017, and requires compliance plan applications to be submitted in 2013. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC is relatively well positioned to comply with the EGU MACT. However, PEF will be required to complete additional emissions controls and/or fleet modernization projects in order to meet the compliance timeframe for the EGU MACT. We are continuing to evaluate the impacts of the EGU MACT on the Utilities. We anticipate that compliance with the EGU MACT will satisfy the North Carolina mercury rule requirements for PEC. The outcome of these matters cannot be predicted.

The CAIR, issued by the EPA, required the District of Columbia and 28 states, including North Carolina, South Carolina and Florida, to reduce NOx and SO_2 emissions. The CAIR set emission limits to be met in two phases beginning in 2009 and 2015, respectively, for NOx and beginning in 2010 and 2015, respectively, for SO_2. States were required to adopt rules implementing the CAIR, and the EPA approved the North Carolina CAIR, the South Carolina CAIR and the Florida CAIR. A 2008 decision by the U.S. Court of Appeals for the District of Columbia (D.C. Court of Appeals) remanded the CAIR without vacating it for the EPA to conduct further proceedings.

On July 7, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR. The CSAPR, slated to take effect on January 1, 2012, contains new emissions trading programs for NOx and SO_2 emissions as well as more stringent overall emissions targets in 27 states, including North Carolina, South Carolina and Florida. A number of parties including groups which PEC and PEF are members of, filed petitions for reconsideration and stay of, as well as legal challenges to, the CSAPR. On December 30, 2011, the D.C. Court of Appeals issued an order staying the implementation of the CSAPR, pending a decision by the court resolving the challenges to the rule. Oral argument for the CSAPR litigation has been scheduled for April 13, 2012. As a result of the stay of CSAPR, the CAIR will remain in effect. The EPA issued the CSAPR as four separate programs, including the NOx annual trading program, the NOx ozone season trading program, the SO_2 Group 1 trading program and the SO_2 Group 2 trading program. If the CSAPR is upheld, North Carolina and South Carolina are included in the NOx and SO_2 annual trading programs, as well as the NOx ozone season program. North Carolina remains classified as a Group 1 state, which will require additional NOx and SO_2 emission reductions beginning in January 2014. South Carolina remains classified as a Group 2 state with no additional reductions required. Under the CSAPR, Florida is subject only to the NOx ozone season program. Due to significant investments in NOx and SO_2 emissions controls and fleet modernization projects completed or under way, we believe PEC and PEF are positioned to comply with the CSAPR without the need for significant capital expenditures. We cannot predict the outcome of this matter.

To date, expenditures at PEF for CAIR regulation primarily relate to environmental compliance projects at Crystal River Units No. 4 and No. 5 (CR4 and CR5), which have both been completed and placed in service. Under an agreement with the FDEP, PEF will retire Crystal River Units No. 1 and No. 2 (CR1 and CR2) as coal-fired units and operate emission control equipment at CR4 and CR5. CR1 and CR2 will be retired after the second proposed nuclear unit at Levy completes its first fuel cycle, which was originally anticipated to be around 2020. As discussed in Note 8B, major construction activities for Levy are being postponed until after the NRC issues the Levy COL. As required, PEF has advised the FDEP of these developments that will delay the retirement of CR1 and CR2 beyond the originally anticipated date. We are currently evaluating the impacts of the Levy schedule on PEF's compliance with environmental regulations. We cannot predict the outcome of this matter.

We account for emission allowances as inventory using the average cost method. Emission allowances are included on the Balance Sheets in inventory and in other assets and deferred debits. We value inventory of the Utilities at historical cost consistent with ratemaking treatment. As previously discussed, the CSAPR establishes new NOx annual and seasonal ozone programs and a new SO_2 trading program. NOx and SO_2 emission allowances applicable to the current CAIR cannot be used to satisfy the new CSAPR programs. SO_2 emission allowances will be utilized by the Utilities to comply with existing Clean Air Act requirements. NOx allowances cannot be utilized to comply with other requirements. As a result of the previously discussed D.C. Court of Appeals order staying the implementation of the CSAPR, the CAIR emission allowance program remains in effect. At December 31, 2011 and December 31, 2010, PEC had an immaterial amount of NOx emission allowances. At December 31, 2011 and December 31, 2010, PEF had approximately $22 million and $28 million, respectively, in NOx emission allowances.

22. COMMITMENTS AND CONTINGENCIES

A. PURCHASE OBLIGATIONS

In most cases, our purchase obligation contracts contain provisions for price adjustments, minimum purchase levels and other financial commitments. The commitment amounts presented below are estimates and therefore will likely differ from actual purchase amounts. At December 31, 2011, the following tables reflect contractual cash obligations and other commercial commitments in the respective periods in which they are due:

Progress Energy

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[a]	$ 2,324	$ 2,053	$ 1,644	$ 1,460	$ 1,182	$ 6,437	$ 15,100
Purchased power	459	440	381	391	373	3,104	5,148
Construction obligations[a]	331	216	35	23	4	10	619
Other purchase obligations	153	100	69	61	71	603	1,057
Total	$ 3,267	$ 2,809	$ 2,129	$ 1,935	$ 1,630	$ 10,154	$ 21,924

PEC

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel	$ 1,173	$ 970	$ 760	$ 718	$ 626	$ 1,864	$ 6,111
Purchased power	79	70	64	70	68	376	727
Construction obligations	277	114	25	19	-	-	435
Other purchase obligations	77	44	47	30	38	242	478
Total	$ 1,606	$ 1,198	$ 896	$ 837	$ 732	$ 2,482	$ 7,751

PEF

(in millions)	2012	2013	2014	2015	2016	Thereafter	Total
Fuel[a]	$ 1,151	$ 1,083	$ 884	$ 742	$ 556	$ 4,573	$ 8,989
Purchased power	380	370	317	321	305	2,728	4,421
Construction obligations[a]	54	102	10	4	4	10	184
Other purchase obligations	64	48	22	31	33	361	559

Total	$ 1,649	$ 1,603	$ 1,233	$ 1,098	$ 898	$ 7,672	$ 14,153

(a) PEF signed an EPC agreement on December 31, 2008, with Westinghouse Electric Company LLC and Stone & Webster, Inc. for two approximately 1,100-MW Westinghouse AP1000 nuclear units planned for construction at Levy. Due to uncertainty regarding the ultimate magnitude and timing of obligations under the EPC agreement and the Levy nuclear fabrication contract, the table includes only the obligations related to the selected components of long lead time equipment as discussed under "Fuel and Purchased Power" and "Construction Obligations."

FUEL AND PURCHASED POWER

Through our subsidiaries, we have entered into various long-term contracts for coal, oil, gas and nuclear fuel as well as transportation agreements for the related fuel. Our purchases under these commitments were $2.697 billion, $2.890 billion and $2.921 billion for 2011, 2010 and 2009, respectively. PEC's purchases were $1.398 billion, $1.489 billion and $1.527 billion in 2011, 2010 and 2009, respectively. PEF's purchases were $1.299 billion, $1.401 billion and $1.394 billion in 2011, 2010 and 2009, respectively. Essentially all fuel and certain purchased power costs incurred by PEC and PEF are eligible for recovery through their respective cost-recovery clauses.

In December 2008, PEF entered into a nuclear fuel fabrication contract that contained exit provisions with termination fees for the planned Levy nuclear units. Due to revisions in the construction schedule and startup dates the nuclear fuel fabrication contract was terminated during 2011. (See discussion following under "Construction Obligations.")

Both PEC and PEF have ongoing purchased power contracts, including renewable energy contracts, with other utilities, certain co-generators and qualified facilities (QFs), with expiration dates ranging from 2012 to 2032. These purchased power contracts generally provide for capacity and energy payments or bundled capacity and energy payments. In addition, both PEC and PEF have various contracts to secure transmission rights. Our purchases under purchased power contracts, including transmission costs, were $925 million, $907 million and $756 million for 2011, 2010 and 2009, respectively. PEC's purchases, including transmission costs, were $253 million, $239 million and $171 million in 2011, 2010 and 2009, respectively. PEF's purchases, including transmission costs, were $672 million, $668 million and $585 million in 2011, 2010 and 2009, respectively.

PEC has executed certain firm contracts for approximately 985 MW of purchased power with other utilities, including tolling contracts, with expiration dates ranging from 2019 to 2022 and representing between 33 percent and 100 percent of plant net output. Minimum purchases under these contracts included in the previous table, representing capital-related capacity costs, are approximately $51 million, $52 million, $53 million, $60 million and $60 million for 2012 through 2016, respectively, and $271 million payable thereafter.

PEC has various pay-for-performance contracts with QFs, including renewable energy, for approximately 81 MW of firm capacity expiring at various times through 2032. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. Payments for both capacity and energy are contingent upon the QFs' ability to generate and, therefore, are not included in the previous table.

PEC has entered into conditional agreements for firm pipeline transportation capacity to support PEC's gas supply needs. Certain agreements are for the period from July 2012 through May 2033. The estimated total cost to PEC associated with these agreements is approximately $1.510 billion, approximately $380 million of which will be classified as a capital lease. Due to the conditions of the capital lease agreement, the capital lease will not be recorded on PEC's balance sheet until mid-2012. The transactions are subject to several conditions precedent, including various state regulatory approvals, the completion and commencement of operation of necessary related interstate and intrastate natural gas pipeline system expansions and other contractual provisions. Due to the conditions of these agreements, the estimated costs associated with these agreements are not currently included in PEC's fuel commitments or in PEC's capital lease assets or obligations.

PEF has executed certain firm contracts for approximately 499 MW of purchased power with other utilities with expiration dates ranging from 2012 to 2016 and representing between 12 percent and 25 percent of plant net output. Minimum purchases under these contracts, representing capital-related capacity costs, are approximately $53 million, $46 million, $65 million, $65 million and $27 million for 2012 through 2016, respectively.

PEF has ongoing purchased power contracts with certain QFs for 682 MW of firm capacity with expiration dates ranging from 2012 to 2025. Energy payments are based on the actual power taken under these contracts. Capacity payments are subject to the QFs meeting certain contract performance obligations. In most cases, these contracts account for 100 percent of the net generating capacity of each of the facilities. All ongoing commitments have been approved by the FPSC. Minimum expected future capacity payments under these contracts are $313 million, $309 million, $238 million, $244 million and $273 million for 2012 through 2016, respectively, and $2.728 billion payable 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.

CONSTRUCTION OBLIGATIONS

We have purchase obligations related to various capital construction projects. Our total payments under these contracts were $507 million, $703 million and $818 million for 2011, 2010 and 2009, respectively.

PEC has purchase obligations related to various capital projects including new generation and transmission obligations. Total payments under PEC's construction-related contracts were $460 million, $555 million and $199 million for 2011, 2010 and 2009, respectively. Payments for 2011 primarily relate to construction of generating facilities at our sites in Wayne County, N.C., and New Hanover County, N.C., as discussed in Note 8B.

PEF has purchase obligations related to capital projects including Levy and various new generation, transmission and environmental compliance projects. Total payments under PEF's construction-related contracts were $47 million, $147 million and $619 million for 2011, 2010 and 2009, respectively, including $6 million, $63 million and $243 million for 2011, 2010 and 2009, respectively, toward long lead equipment and engineering related to the Levy EPC.

The future construction obligations presented in the previous tables for Progress Energy and PEF exclude PEF's Levy EPC agreement. The EPC agreement includes provisions for termination. For termination without cause, the EPC agreement contains exit provisions with termination fees, which may be significant, that vary based on the termination circumstances. As discussed in Note 8C, in 2010 PEF identified a schedule shift in the Levy project, and major construction activities on Levy have been postponed until after the NRC issues the COL for the plants, which is expected in 2013 if the current licensing schedule remains on track. We executed an amendment to the EPC agreement in 2010 due to the schedule shifts. Additionally, in light of the schedule shifts in the Levy nuclear project, PEF completed vendor negotiations in July 2011 to continue or suspend purchase orders for long lead time equipment without material fees or charges. Prior to the EPC amendment, estimated payments and associated escalations were $8.608 billion for the multi-year contract and did not assume any joint ownership. Because we have executed an amendment to the EPC agreement and anticipate negotiating additional amendments upon receipt of the COL, we cannot currently predict when those obligations will be satisfied or the magnitude of any change. PEF has continued with selected components of long lead time equipment. Work was suspended on the remaining long lead time equipment items, which have total remaining estimated payments and associated escalations of approximately $1.250 billion included in the previously discussed $8.608 billion. We cannot predict the outcome of this matter.

OTHER PURCHASE OBLIGATIONS

We have various other contractual obligations primarily related to PESC service contracts for operational services, PEC service agreements related to its Smith Energy Complex, Wayne County, N.C., and New Hanover County, N.C., generating facilities, and PEF service agreements related to the Hines Energy Complex and the Bartow Plant. Our payments under these agreements were $151 million, $124 million and $56 million for 2011, 2010 and 2009, respectively.

PEC has various other purchase obligations, including obligations for long-term service agreements, parts and equipment, limestone supply and fleet vehicles. Total purchases under these contracts were $73 million, $55 million and $14 million for 2011, 2010 and 2009, respectively.

PEF has various other purchase obligations, including long-term service agreements for the Hines Energy Complex and the Bartow Plant. Total payments under these contracts were $54 million, $35 million and $22 million for 2011, 2010 and 2009, respectively. Future obligations are primarily comprised of the long-term service agreements.

B. LEASES

We and the Utilities lease office buildings, computer equipment, vehicles, railcars and other property and equipment with various terms and expiration dates. Additionally, the Utilities have entered into certain purchased power agreements, which are classified as leases. Some rental payments for transportation equipment include minimum rentals plus contingent rentals based on mileage. These contingent rentals are not significant.

Our rent expense under operating leases other than for purchased power totaled $42 million, $39 million and $37 million for 2011, 2010 and 2009, respectively. Our purchased power expense under agreements classified as operating leases was approximately $62 million, $61 million and $11 million in 2011, 2010 and 2009, respectively.

In 2003, we entered into an operating lease for a building for which minimum annual rental payments are approximately $7 million. The lease term expires July 2035 and provides for no rental payments during the last 15 years of the lease, during which period $53 million of rental expense will be recorded on the Consolidated Statements of Income. See Note 2 regarding our exit plan to vacate and sublease this building.

PEC's rent expense under operating leases other than for purchased power totaled $26 million, $25 million and $26 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEC of $5 million in 2011, 2010 and 2009.

PEC has entered into purchased power agreements that are classified as operating leases. These agreements, which have total minimum payments of approximately $512 million and expire through 2032, primarily relate to two tolling agreements for purchased power of approximately 576 MW (100 percent of net output). Purchased power expense under agreements classified as operating leases was approximately $62 million, $38 million and $11 million in 2011, 2010 and 2009, respectively.

PEF's rent expense under operating leases other than for purchased power totaled $15 million, $14 million and $11 million during 2011, 2010 and 2009, respectively. These amounts include rent expense allocated from PESC to PEF of $4 million in 2011 and $3 million in 2010 and 2009.

PEF has entered into a purchased power tolling agreement that is classified as an operating lease. This agreement for approximately 640 MW (100 percent of net output) has minimum annual payments beginning in June 2012 and expires in 2027 with total minimum payments of approximately $421 million. Purchased power expense under agreements classified as operating leases was approximately $23 million in 2010. PEF had no purchased power expense under operating lease agreements in 2011 and 2009.

PEF has a capital lease for a building and one tolling agreement for purchased power, which is classified as a capital lease of the related plant. PEF entered into the agreement for the building in 2005 and the lease term expires in 2047. The agreement for the building provides for minimum annual payments from 2007 through 2026 and no payments from 2027 through 2047. The minimum annual payments are approximately $5 million, for a total of approximately $103 million. During the last 20 years of the building lease, approximately $51 million of rental expense will be recorded on the Statements of Income. The 517-MW (100 percent of net output) tolling agreement for purchased power has minimum annual payments of approximately $21 million from 2007 through 2024, for a total of approximately $348 million.

Assets recorded under capital leases, including plant related to purchased power agreements, at December 31, consisted of:

	Progress Energy		PEC		PEF	
(in millions)	**2011**	2010	**2011**	2010	**2011**	2010
Buildings	**$ 267**	$ 267	**$ 30**	$ 30	**$ 237**	$ 237
Less: Accumulated amortization	**(56)**	(46)	**(18)**	(17)	**(38)**	(29)
Total	**$ 211**	$ 221	**$ 12**	$ 13	**$ 199**	$ 208

Consistent with the ratemaking treatment for capital leases, capital lease expenses are charged to the same accounts that would be used if the leases were operating leases. Thus, our and the Utilities' capital lease expense is generally included in O&M or purchased power expense. Our capital lease expense totaled $25 million, $25 million and $26 million for 2011, 2010 and 2009, respectively, which was primarily comprised of PEF's capital lease expense of $23 million, $23 million and $24 million for 2011, 2010 and 2009, respectively.

At December 31, 2011, minimum annual payments, excluding executory costs such as property taxes, insurance and maintenance, under long-term noncancelable operating and capital leases were:

	Progress Energy		PEC		PEF	
(in millions)	Capital	Operating	Capital	Operating	Capital	Operating
2012	$ 28	$ 61	$ 2	$ 28	$ 26	$ 27
2013	36	85	10	43	26	36
2014	26	82	-	42	26	35
2015	26	79	-	43	26	34
2016	25	79	-	43	25	34
Thereafter	201	791	6	472	195	318
Minimum annual payments	342	1,177	18	671	324	484
Less amount representing imputed interest	(131)		(6)		(125)	
Total	$ 211	$ 1,177	$ 12	$ 671	$ 199	$ 484

The Utilities are lessors of electric poles, streetlights and other facilities. PEC's rents received are primarily contingent upon usage and totaled $35 million, $33 million, and $34 million for 2011, 2010 and 2009, respectively. PEC's minimum rentals receivable under noncancelable leases are $12 million for 2012 and none thereafter. PEF's rents received are based on a fixed minimum rental where price varies by type of equipment or contingent usage and totaled $86 million, $85 million and $84 million for 2011, 2010 and 2009, respectively. PEF's minimum rentals receivable under noncancelable leases are not material for 2012 and thereafter.

C. GUARANTEES

As a part of normal business, we enter into various agreements providing future financial or performance assurances to third parties. Such agreements include guarantees, standby letters of credit and surety bonds. At December 31, 2011, we do not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the accompanying Balance Sheets.

At December 31, 2011, we have issued guarantees and indemnifications of and for certain asset performance, legal, tax and environmental matters to third parties, including indemnifications made in connection with sales of businesses. At December 31, 2011, our estimated maximum exposure for guarantees and indemnifications for which a maximum exposure is determinable was $337 million, including $61 million at PEF. Related to the sales of businesses, the latest specified notice period extends until 2013 for the majority of legal, tax and environmental matters provided for in the indemnification provisions. Indemnifications for the performance of assets extend to 2016. For certain matters for which we receive timely notice, our indemnity obligations may extend beyond the notice period. Certain indemnifications related to discontinued operations have no limitations as to time or maximum potential future payments. As part of settlement agreements entered into in 2002, PEF is responsible for providing the joint owners of CR3 a specified amount of generating capacity through the expiration of the indemnification provisions of the joint owner agreement in 2013. Due to the CR3 outage (See Note 8C), PEF has been unable to meet the required generating capacity and has provided replacement power from other generation sources or purchased power. During the year ended December 31, 2011, we and PEF recorded indemnification charges totaling $48 million for estimated joint owner replacement power costs for 2011 and future years, and provided replacement power totaling $21 million. At December 31, 2011 and 2010, we had recorded liabilities related to guarantees and indemnifications to third parties of $63 million and $31 million, respectively. These amounts included $37 million and $6 million for PEF at December 31, 2011 and 2010, respectively. As current estimates change, additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded in the future.

In addition, the Parent has issued $300 million in guarantees for certain payments of two wholly owned indirect subsidiaries (See Note 23).

D. OTHER COMMITMENTS AND CONTINGENCIES

MERGER

During January and February 2011, Progress Energy and its directors were named as defendants in 11 purported class action lawsuits with 10 lawsuits brought in the Superior Court, Wake County, N.C., and one lawsuit filed in the United States District Court for the Eastern District of North Carolina, each in connection with the Merger (we refer to these lawsuits as the "actions"). The complaints in the actions alleged, among other things, that the Merger Agreement was the product of breaches of fiduciary duty by the individual defendants, in that it allegedly did not provide for full and fair value for Progress Energy's shareholders; that the Merger Agreement contained coercive deal protection measures; and that the Merger Agreement and the Merger were approved as a result, allegedly, of improper self-dealing by certain defendants who would receive certain alleged employment compensation benefits and continued employment pursuant to the Merger Agreement. The complaints in the actions also alleged that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. As relief, the plaintiffs in the actions sought, among other things, to enjoin completion of the Merger.

Additionally, the complaint in the federal action was amended in early April 2011 to include allegations that the defendants violated federal securities laws in connection with statements contained in the registration statement filed on Form S-4 by Duke Energy related to the Merger (the Registration Statement).

On March 31, 2011, counsel for the federal action plaintiff sent a derivative demand letter to Mr. William D. Johnson, Chairman, President and CEO of Progress Energy, demanding that the Progress Energy board of directors desist from moving forward with the Merger, make certain disclosures and engage in an auction of the company. Also on March 31, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 13, 2011, counsel for the federal action plaintiff sent another derivative demand letter to Mr. Johnson further demanding that the Progress Energy board of directors desist from moving forward with the Merger unless certain changes are made to the Merger Agreement and additional disclosures are made. Also on April 13, 2011, the same counsel sent Mr. Johnson a substantially identical derivative demand letter on behalf of two other purported Progress Energy shareholders.

On April 25, 2011, the Progress Energy board of directors established a special committee of disinterested directors to conduct a review and evaluation of the allegations and legal claims set forth in the derivative demand letters. The special committee investigated the allegations and legal claims and determined there was no basis to pursue the claims.

By order dated June 17, 2011, the court consolidated the state court cases. On June 21, 2011, the plaintiffs in the state court actions filed a verified consolidated amended complaint in the consolidated state court actions alleging breach of fiduciary duty by the individual defendants, and that Progress Energy aided and abetted the individual defendants' alleged breaches of fiduciary duty. The verified consolidated amended complaint further alleged that the Registration Statement and amendments filed on April 8, April 25, and May 13, 2011, failed to disclose material facts, giving rise to plaintiffs' claims.

On July 11, 2011, solely to avoid the costs, risks and uncertainties inherent in litigation and to allow its shareholders to vote on the proposals required in connection with the Merger at its special meeting of its shareholders, Progress Energy entered into a memorandum of understanding with plaintiffs in the consolidated state court actions and other named defendants to settle the consolidated action and all related claims that were or could have been asserted in other actions, subject to court approval. The details of the settlement were set forth in a notice sent to Progress Energy's shareholders of record that were members of the class as of July 5, 2011.

On November 29, 2011, the court entered a final order and judgment approving the settlement as fair, reasonable and adequate and awarded legal fees and expenses to plaintiffs' counsel of $550,000. The court dismissed the action with prejudice and released and fully discharged all claims, including federal claims, which had been or could be in the future asserted in the action or in any court, tribunal or proceeding. On December 8, 2011, the federal action was voluntarily dismissed.

ENVIRONMENTAL

We are subject to federal, state and local regulations regarding environmental matters (See Note 21).

Hurricane Katrina

In May 2011, PEC and PEF were named in a class action lawsuit filed in the U.S. District Court for the Southern District of Mississippi. Plaintiffs claim that PEC and PEF, along with numerous other utility, oil, coal and chemical companies, are liable for damages relating to losses suffered by victims of Hurricane Katrina. Plaintiffs claim that defendants' greenhouse gas emissions contributed to the frequency and intensity of storms such as Hurricane Katrina. We believe the plaintiffs' claim is without merit; however, we cannot predict the outcome of this matter.

Water Discharge Permit

On October 5, 2011, Earthjustice, on behalf of the Sierra Club and Florida Wildlife Federation, filed a petition seeking review of the water discharge permit issued to CR1, CR2 and CR3 raising a number of technical and legal issues with respect to the permit. A settlement has been tentatively reached providing for the withdrawal of the petition and issuance of a revised water discharge permit identical in form to the one under appeal but with an 18 month term. The current permit has a five year term. The settlement, if finalized, will fully resolve the current dispute. We cannot predict the outcome of this matter.

SPENT NUCLEAR FUEL MATTERS

Pursuant to the Nuclear Waste Policy Act of 1982, the Utilities entered into contracts with the 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.

The DOE failed to begin taking spent nuclear fuel by January 31, 1998. In January 2004, the Utilities filed a complaint in the U.S. Court of Federal Claims against the DOE, claiming that the DOE breached the Standard Contract for Disposal of Spent Nuclear Fuel by failing to accept spent nuclear fuel from our various facilities on or before January 31, 1998. The Utilities have asserted over $90 million in damages incurred between January 31, 1998, and December 31, 2005, the time period set by the court for damages in this case.

On June 14, 2011, the judge in the U.S. Court of Federal Claims issued a ruling to award the Utilities substantially all their asserted damages. In September 2011, after the government dismissed its notice of appeal, the judgment became final. As a result, in September 2011, PEC recorded the $92 million award as an offset for past spent fuel storage costs incurred, of which $27 million was O&M expense. PEC received the cash award in January 2012.

On December 12, 2011, the Utilities filed another complaint in the U.S. Court of Federal Claims against the DOE, claiming damages incurred from January 1, 2006, through December 31, 2010. The damages stem from the same breach of contract asserted in the previous litigation. The Utilities may file subsequent damage claims as they incur additional costs. We cannot predict the outcome of this matter.

SYNTHETIC FUELS MATTERS

On October 21, 2009, a jury delivered a verdict in a lawsuit against Progress Energy and a number of our subsidiaries and affiliates arising out of an Asset Purchase Agreement dated as of October 19, 1999, and amended as of August 23, 2000 (the Asset Purchase Agreement), by and among U.S. Global, LLC (Global); Earthco; certain affiliates of Earthco; EFC Synfuel LLC (which was owned indirectly by Progress Energy, Inc.) and certain of its affiliates, including Solid Energy LLC; Solid Fuel LLC; Ceredo Synfuel LLC; Gulf Coast Synfuel LLC (renamed Sandy River Synfuel LLC) (collectively, the Progress Affiliates), as amended by an amendment to the Asset Purchase Agreement. In a case filed in the Circuit Court for Broward County, Fla., in March 2003 (the Florida Global Case), Global requested an unspecified amount of compensatory damages, as well as declaratory relief. Global asserted (1) that pursuant to the Asset Purchase Agreement, it was entitled to an interest in two synthetic fuels facilities previously owned by the Progress Affiliates and an option to purchase additional interests in the two synthetic fuels facilities and (2) that it was entitled to damages because the Progress Affiliates prohibited it from procuring purchasers for the synthetic fuels facilities. As a result of the expiration of the Section 29 tax credit program on December 31, 2007, all of our synthetic fuels businesses were abandoned and we reclassified our synthetic fuels businesses as discontinued operations.

The jury awarded Global $78 million. On October 23, 2009, Global filed a motion to assess prejudgment interest on the award. On November 20, 2009, the court granted the motion and assessed $55 million in prejudgment interest and entered judgment in favor of Global in a total amount of $133 million. During the year ended December 31, 2009, we recorded an after-tax charge of $74 million to discontinued operations. On December 18, 2009, we appealed the Broward County judgment to the Florida Fourth District Court of Appeals. Also in December 2009, we made a $154 million payment, which represents payment of the total judgment and a required premium equivalent to two years of interest, to the Broward County Clerk of Court bond account. The appellate briefing process has been completed. Oral argument was held on September 27, 2011. We cannot predict the outcome of this matter.

In a second suit filed in the Superior Court for Wake County, N.C., *Progress Synfuel Holdings, Inc. et al. v. U.S. Global, LLC* (the North Carolina Global Case), the Progress Affiliates seek declaratory relief consistent with our interpretation of the Asset Purchase Agreement. Global was served with the North Carolina Global Case on April 17, 2003.

On May 15, 2003, Global moved to dismiss the North Carolina Global Case for lack of personal jurisdiction over Global. In the alternative, Global requested that the court decline to exercise its discretion to hear the Progress Affiliates' declaratory judgment action. On August 7, 2003, the Wake County Superior Court denied Global's motion to dismiss, but stayed the North Carolina Global Case, pending the outcome of the Florida Global Case. The Progress Affiliates appealed the superior court's order staying the case. By order dated September 7, 2004, the North Carolina Court of Appeals dismissed the Progress Affiliates' appeal. Based upon the verdict in the Florida Global Case, we anticipate dismissal of the North Carolina Global Case.

CLAIM OF HOLDER OF CONTINGENT VALUE OBLIGATIONS

On June 10, 2011, Davidson Kempner Partners, M.H. Davidson & Co., Davidson Kempner Institutional Partners, L.P., and Davidson Kempner International, Ltd. (jointly, Davidson Kempner) filed a lawsuit against us in the Supreme Court of the State of New York, County of New York. Davidson Kempner is a holder of CVOs (See Note 16) and alleged that we improperly deducted escrow deposits in 2005 in determining net after-tax cash flow under the agreement governing the CVOs and that by taking this position, we breached our obligation under the agreement to exercise good faith and fair dealing. The plaintiffs alleged that this breach caused injury to the holders of CVOs in the approximate amount of $42 million. The plaintiffs requested declaratory judgment to require that we deduct the escrowed payments in 2006.

On August 2, 2011, the parties filed a Stipulation of Discontinuance without Prejudice to dismiss the state lawsuit so that certain of the plaintiffs could file a federal lawsuit against us. On August 9, 2011, M.H. Davidson & Co. and Davidson Kempner International, Ltd. filed a lawsuit against us in the United States District Court for the Southern District of New York with the same allegations and seeking the same relief as the prior state lawsuit. On October 3, 2011, we entered a settlement agreement and release with Davidson

Kempner under which the parties mutually released all claims related to the CVOs and we purchased all of Davidson Kempner's CVOs at a negotiated purchase price of $0.75 per CVO. The parties to the federal lawsuit filed a Stipulation of Discontinuance with Prejudice dismissing the lawsuit on October 12, 2011.

OTHER LITIGATION MATTERS

We and our subsidiaries are involved in various litigation matters in the ordinary course of business, some of which involve substantial amounts. Where appropriate, we have made accruals and disclosures to provide for such matters. In the opinion of management, the final disposition of pending litigation would not have a material adverse effect on our consolidated results of operations or financial position.

23. CONDENSED CONSOLIDATING STATEMENTS

Presented below are the Condensed Consolidating Statements of Income, Balance Sheets and Cash Flows as required by Rule 3-10 of Regulation S-X. In September 2005, we issued our guarantee of certain payments of two wholly owned indirect subsidiaries, FPC Capital I (the Trust) and Florida Progress Funding Corporation (Funding Corp.). Our guarantees are in addition to the previously issued guarantees of our wholly owned subsidiary, Florida Progress.

The Trust, a finance subsidiary, was established in 1999 for the sole purpose of issuing $300 million of 7.10% Cumulative Quarterly Income Preferred Securities due 2039, Series A (Preferred Securities), and using the proceeds thereof to purchase from Funding Corp. $300 million of 7.10% Junior Subordinated Deferrable Interest Notes due 2039 (Subordinated Notes). The Trust has no other operations and its sole assets are the Subordinated Notes and Notes Guarantee (as discussed below). Funding Corp. is a wholly owned subsidiary of Florida Progress and was formed for the sole purpose of providing financing to Florida Progress and its subsidiaries. Funding Corp. does not engage in business activities other than such financing and has no independent operations. Since 1999, Florida Progress has fully and unconditionally guaranteed the obligations of Funding Corp. under the Subordinated Notes. In addition, Florida Progress guaranteed the payment of all distributions related to the Preferred Securities required to be made by the Trust, but only to the extent that the Trust has funds available for such distributions (the Preferred Securities Guarantee). The two guarantees considered together constitute a full and unconditional guarantee by Florida Progress of the Trust's obligations under the Preferred Securities. The Preferred Securities and the Preferred Securities Guarantee are listed on the New York Stock Exchange.

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

We have guaranteed the payment of all distributions related to the Trust's Preferred Securities. At December 31, 2011, the Trust had outstanding 12 million shares of the Preferred Securities with a liquidation value of $300 million. Our guarantees are joint and several, full and unconditional, and are in addition to the joint and several, full and unconditional guarantees previously issued to the Trust and Funding Corp. by Florida Progress. Our subsidiaries have provisions restricting the payment of dividends to the Parent in certain limited circumstances, and as disclosed in Note 12B, there were no restrictions on PEC's or PEF's retained earnings.

The Trust is a variable-interest entity of which we are not the primary beneficiary. Separate financial statements and other disclosures concerning the Trust have not been presented because we believe that such information is not material to investors.

In these condensed consolidating statements, the Parent column includes the financial results of the parent holding company only. The Subsidiary Guarantor column includes the consolidated financial results of Florida Progress only, which is primarily comprised of its wholly owned subsidiary PEF. The Non-Guarantor Subsidiaries column includes the consolidated financial results of all non-guarantor subsidiaries, which is primarily comprised of our wholly owned subsidiary PEC. The Other column includes elimination entries for all intercompany transactions and other consolidation adjustments. Financial statements for PEC and PEF are separately presented elsewhere in this Form 10-K. All applicable corporate expenses have been allocated appropriately among the guarantor and non-guarantor subsidiaries. The financial information may not necessarily be indicative of results of operations or financial position had the subsidiary guarantor or other non-guarantor subsidiaries operated as independent entities.

Condensed Consolidating Statement of Income
Year ended December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 4,379	$ 4,528	$ -	$ 8,907
Affiliate revenues	-	-	272	(272)	-
Total operating revenues	-	4,379	4,800	(272)	8,907
Operating expenses					
Fuel used in electric generation	-	1,506	1,387	-	2,893
Purchased power	-	778	315	-	1,093
Operation and maintenance	10	881	1,407	(262)	2,036
Depreciation, amortization and accretion	-	169	532	-	701
Taxes other than on income	-	350	218	(6)	562
Other	-	(1)	35	-	34
Total operating expenses	10	3,683	3,894	(268)	7,319
Operating (loss) income	(10)	696	906	(4)	1,588
Other income (expense)					
Interest income	-	1	2	(1)	2
Allowance for equity funds used during construction	-	32	71	-	103
Other, net	(61)	5	(4)	2	(58)
Total other (expense) income, net	(61)	38	69	1	47
Interest charges					
Interest charges	279	276	205	-	760
Allowance for borrowed funds used during construction	-	(14)	(21)	-	(35)
Total interest charges, net	279	262	184	-	725
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(350)	472	791	(3)	910
Income tax (benefit) expense	(127)	170	275	5	323
Equity in earnings of consolidated subsidiaries	798	-	-	(798)	-
Income from continuing operations	575	302	516	(806)	587
Discontinued operations, net of tax	-	(3)	(2)	-	(5)
Net income	575	299	514	(806)	582
Net income attributable to noncontrolling interests, net of tax	-	(4)	-	(3)	(7)
Net income attributable to controlling interests	$ 575	$ 295	$ 514	$ (809)	$ 575

Condensed Consolidating Statement of Income
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 5,268	$ 4,922	$ -	$ 10,190
Affiliate revenues	-	-	248	(248)	-
Total operating revenues	-	5,268	5,170	(248)	10,190
Operating expenses					
Fuel used in electric generation	-	1,614	1,686	-	3,300
Purchased power	-	977	302	-	1,279
Operation and maintenance	7	912	1,345	(237)	2,027
Depreciation, amortization and accretion	-	426	494	-	920
Taxes other than on income	-	362	225	(7)	580
Other	-	17	13	-	30
Total operating expenses	7	4,308	4,065	(244)	8,136
Operating (loss) income	(7)	960	1,105	(4)	2,054
Other income (expense)					
Interest income	7	2	5	(7)	7
Allowance for equity funds used during construction	-	28	64	-	92
Other, net	(1)	1	(3)	3	-
Total other income, net	6	31	66	(4)	99
Interest charges					
Interest charges	282	293	211	(7)	779
Allowance for borrowed funds used during construction	-	(13)	(19)	-	(32)
Total interest charges, net	282	280	192	(7)	747
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(283)	711	979	(1)	1,406
Income tax (benefit) expense	(111)	267	378	5	539
Equity in earnings of consolidated subsidiaries	1,027	-	-	(1,027)	-
Income from continuing operations	855	444	601	(1,033)	867
Discontinued operations, net of tax	1	(1)	(4)	-	(4)
Net income	856	443	597	(1,033)	863
Net (income) loss attributable to noncontrolling interests, net of tax	-	(4)	1	(4)	(7)
Net income attributable to controlling interests	$ 856	$ 439	$ 598	$ (1,037)	$ 856

Condensed Consolidating Statement of Income
Year ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Operating revenues					
Operating revenues	$ -	$ 5,259	$ 4,626	$ -	$ 9,885
Affiliate revenues	-	-	235	(235)	-
Total operating revenues	-	5,259	4,861	(235)	9,885
Operating expenses					
Fuel used in electric generation	-	2,072	1,680	-	3,752
Purchased power	-	682	229	-	911
Operation and maintenance	8	839	1,269	(222)	1,894
Depreciation, amortization and accretion	-	502	484	-	986
Taxes other than on income	-	347	216	(6)	557
Other	-	13	-	-	13
Total operating expenses	8	4,455	3,878	(228)	8,113
Operating (loss) income	(8)	804	983	(7)	1,772
Other income (expense)					
Interest income	10	5	9	(10)	14
Allowance for equity funds used during construction	-	91	33	-	124
Other, net	18	6	(22)	4	6
Total other income, net	28	102	20	(6)	144
Interest charges					
Interest charges	233	280	215	(10)	718
Allowance for borrowed funds used during construction	-	(27)	(12)	-	(39)
Total interest charges, net	233	253	203	(10)	679
(Loss) income from continuing operations before income tax and equity in earnings of consolidated subsidiaries	(213)	653	800	(3)	1,237
Income tax (benefit) expense	(93)	200	286	4	397
Equity in earnings of consolidated subsidiaries	875	-	-	(875)	-
Income from continuing operations	755	453	514	(882)	840
Discontinued operations, net of tax	2	(43)	(38)	-	(79)
Net income	757	410	476	(882)	761
Net (income) loss attributable to noncontrolling interests, net of tax	-	(3)	2	(3)	(4)
Net income attributable to controlling interests	$ 757	$ 407	$ 478	$ (885)	$ 757

Condensed Consolidating Balance Sheet
December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,523	$ 11,887	$ 87	$ 22,497
Current assets					
Cash and cash equivalents	117	92	21	-	230
Receivables, net	-	372	517	-	889
Notes receivable from affiliated companies	53	-	219	(272)	-
Regulatory assets	-	244	31	-	275
Derivative collateral posted	-	123	24	-	147
Prepayments and other current assets	128	852	1,049	(87)	1,942
Total current assets	298	1,683	1,861	(359)	3,483
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,043	-	-	(14,043)	-
Regulatory assets	-	1,602	1,423	-	3,025
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	559	1,088	-	1,647
Other assets and deferred debits	140	242	856	(486)	752
Total deferred debits and other assets	14,183	2,403	3,367	(10,874)	9,079
Total assets	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,021	$ 4,728	$ 5,646	$ (10,374)	$ 10,021
Noncontrolling interests	-	4	-	-	4
Total equity	10,021	4,732	5,646	(10,374)	10,025
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,543	4,482	3,693	-	11,718
Total capitalization	13,564	9,557	9,398	(10,410)	22,109
Current liabilities					
Current portion of long-term debt	450	-	500	-	950
Short-term debt	250	233	188	-	671
Notes payable to affiliated companies	-	238	34	(272)	-
Derivative liabilities	38	268	130	-	436
Other current liabilities	161	839	1,112	(84)	2,028
Total current liabilities	899	1,578	1,964	(356)	4,085
Deferred credits and other liabilities					
Noncurrent income tax liabilities	-	837	1,976	(458)	2,355
Regulatory liabilities	-	1,071	1,543	86	2,700
Other liabilities and deferred credits	18	1,566	2,234	(8)	3,810
Total deferred credits and other liabilities	18	3,474	5,753	(380)	8,865
Total capitalization and liabilities	$ 14,481	$ 14,609	$ 17,115	$ (11,146)	$ 35,059

Condensed Consolidating Balance Sheet
December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
ASSETS					
Utility plant, net	$ -	$ 10,189	$ 10,961	$ 90	$ 21,240
Current assets					
Cash and cash equivalents	110	270	231	-	611
Receivables, net	-	497	536	-	1,033
Notes receivable from affiliated companies	14	48	115	(177)	-
Regulatory assets	-	105	71	-	176
Derivative collateral posted	-	140	24	-	164
Prepayments and other current assets	30	751	984	(273)	1,492
Total current assets	154	1,811	1,961	(450)	3,476
Deferred debits and other assets					
Investment in consolidated subsidiaries	14,316	-	-	(14,316)	-
Regulatory assets	-	1,387	987	-	2,374
Goodwill	-	-	-	3,655	3,655
Nuclear decommissioning trust funds	-	554	1,017	-	1,571
Other assets and deferred debits	75	238	894	(469)	738
Total deferred debits and other assets	14,391	2,179	2,898	(11,130)	8,338
Total assets	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054
CAPITALIZATION AND LIABILITIES					
Equity					
Common stock equity	$ 10,023	$ 4,957	$ 5,686	$ (10,643)	$ 10,023
Noncontrolling interests	-	4	-	-	4
Total equity	10,023	4,961	5,686	(10,643)	10,027
Preferred stock of subsidiaries	-	34	59	-	93
Long-term debt, affiliate	-	309	-	(36)	273
Long-term debt, net	3,989	4,182	3,693	-	11,864
Total capitalization	14,012	9,486	9,438	(10,679)	22,257
Current liabilities					
Current portion of long-term debt	205	300	-	-	505
Notes payable to affiliated companies	-	175	3	(178)	-
Derivative liabilities	18	188	53	-	259
Other current liabilities	278	1,002	1,184	(273)	2,191
Total current liabilities	501	1,665	1,240	(451)	2,955
Deferred credits and other liabilities					
Noncurrent income tax liabilities	3	528	1,608	(443)	1,696
Regulatory liabilities	-	1,084	1,461	90	2,635
Other liabilities and deferred credits	29	1,416	2,073	(7)	3,511
Total deferred credits and other liabilities	32	3,028	5,142	(360)	7,842
Total capitalization and liabilities	$ 14,545	$ 14,179	$ 15,820	$ (11,490)	$ 33,054

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2011

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 756	$ 706	$ 1,251	$ (1,098)	$ 1,615
Investing activities					
Gross property additions	-	(818)	(1,248)	-	(2,066)
Nuclear fuel additions	-	(15)	(211)	-	(226)
Purchases of available-for-sale securities and other investments	-	(4,438)	(579)	-	(5,017)
Proceeds from available-for-sale securities and other investments	-	4,441	529	-	4,970
Changes in advances to affiliated companies	(38)	48	(104)	94	-
Contributions to consolidated subsidiaries	(11)	-	-	11	-
Other investing activities	(24)	121	29	1	127
Net cash used by investing activities	(73)	(661)	(1,584)	106	(2,212)
Financing activities					
Issuance of common stock, net	53	-	-	-	53
Dividends paid on common stock	(734)	-	-	-	(734)
Dividends paid to parent	-	(513)	(585)	1,098	-
Net decrease in short-term debt	250	233	185	(1)	667
Proceeds from issuance of long-term debt, net	495	296	495	-	1,286
Retirement of long-term debt	(700)	(300)	-	-	(1,000)
Changes in advances from affiliated companies	-	63	31	(94)	-
Contributions from parent	-	10	1	(11)	-
Other financing activities	(40)	(12)	(4)	-	(56)
Net cash (used) provided by financing activities	(676)	(223)	123	992	216
Net increase (decrease) in cash and cash equivalents	7	(178)	(210)	-	(381)
Cash and cash equivalents at beginning of year	110	270	231	-	611
Cash and cash equivalents at end of year	$ 117	$ 92	$ 21	$ -	$ 230

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2010

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 16	$ 1,181	$ 1,562	$ (222)	$ 2,537
Investing activities					
Gross property additions	-	(1,014)	(1,231)	24	(2,221)
Nuclear fuel additions	-	(38)	(183)	-	(221)
Purchases of available-for-sale securities and other investments	-	(6,391)	(618)	-	(7,009)
Proceeds from available-for-sale securities and other investments	-	6,395	595	-	6,990
Changes in advances to affiliated companies	15	(2)	188	(201)	-
Return of investment in consolidated subsidiaries	54	-	-	(54)	-
Contributions to consolidated subsidiaries	(171)	-	-	171	-
Other investing activities	113	60	3	(115)	61
Net cash provided (used) by investing activities	11	(990)	(1,246)	(175)	(2,400)
Financing activities					
Issuance of common stock, net	434	-	-	-	434
Dividends paid on common stock	(717)	-	-	-	(717)
Dividends paid to parent	-	(102)	(100)	202	-
Dividends paid to parent in excess of retained earnings	-	-	(54)	54	-
Net decrease in short-term debt	(140)	-	-	-	(140)
Proceeds from issuance of long-term debt, net	-	591	-	-	591
Retirement of long-term debt	(100)	(300)	-	-	(400)
Changes in advances from affiliated companies	-	(201)	-	201	-
Contributions from parent	-	33	152	(185)	-
Other financing activities	-	(14)	(130)	125	(19)
Net cash (used) provided by financing activities	(523)	7	(132)	397	(251)
Net (decrease) increase in cash and cash equivalents	(496)	198	184	-	(114)
Cash and cash equivalents at beginning of year	606	72	47	-	725
Cash and cash equivalents at end of year	$ 110	$ 270	$ 231	$ -	$ 611

Condensed Consolidating Statement of Cash Flows
Year ended December 31, 2009

(in millions)	Parent	Subsidiary Guarantor	Non-Guarantor Subsidiaries	Other	Progress Energy, Inc.
Net cash provided by operating activities	$ 108	$ 1,079	$ 1,282	$ (198)	$ 2,271
Investing activities					
Gross property additions	-	(1,449)	(858)	12	(2,295)
Nuclear fuel additions	-	(78)	(122)	-	(200)
Proceeds from sales of assets to affiliated companies	-	-	11	(11)	-
Purchases of available-for-sale securities and other investments	-	(1,548)	(802)	-	(2,350)
Proceeds from available-for-sale securities and other investments	-	1,558	756	-	2,314
Changes in advances to affiliated companies	4	(2)	(172)	170	-
Return of investment in consolidated subsidiaries	12	-	-	(12)	-
Contributions to consolidated subsidiaries	(688)	-	-	688	-
Other investing activities	-	-	(1)	-	(1)
Net cash used by investing activities	(672)	(1,519)	(1,188)	847	(2,532)
Financing activities					
Issuance of common stock, net	623	-	-	-	623
Dividends paid on common stock	(693)	-	-	-	(693)
Dividends paid to parent	-	(1)	(200)	201	-
Dividends paid to parent in excess of retained earnings	-	-	(12)	12	-
Payments of short-term debt with original maturities greater than 90 days	(629)	-	-	-	(629)
Net increase (decrease) in short-term debt	100	(371)	(110)	-	(381)
Proceeds from issuance of long-term debt, net	1,683	-	595	-	2,278
Retirement of long-term debt	-	-	(400)	-	(400)
Changes in advances from affiliated companies	-	170	-	(170)	-
Contributions from parent	-	653	49	(702)	-
Other financing activities	(2)	(12)	12	10	8
Net cash provided (used) by financing activities	1,082	439	(66)	(649)	806
Net increase (decrease) in cash and cash equivalents	518	(1)	28	-	545
Cash and cash equivalents at beginning of year	88	73	19	-	180
Cash and cash equivalents at end of year	$ 606	$ 72	$ 47	$ -	$ 725

24. QUARTERLY FINANCIAL DATA (UNAUDITED)

Summarized quarterly financial data was as follows:

Progress Energy

(in millions except per share data)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 2,167**	**$ 2,256**	**$ 2,747**	**$ 1,737**
Operating income	**451**	**428**	**690**	**19**
Income (loss) from continuing operations	**187**	**180**	**293**	**(73)**
Net income (loss)	**185**	**178**	**293**	**(74)**
Net income (loss) attributable to controlling interests	**184**	**176**	**291**	**(76)**
Common stock data				
Basic and diluted earnings per common share				
Income (loss) from continuing operations attributable to controlling interests, net of tax	**0.63**	**0.60**	**0.98**	**(0.25)**
Net income (loss) attributable to controlling interests	**0.62**	**0.60**	**0.98**	**(0.25)**
Dividends declared per common share	**0.620**	**0.620**	**0.620**	**0.259**
Market price per share				
High	**46.83**	**49.03**	**52.42**	**56.33**
Low	**42.55**	**45.20**	**42.05**	**49.37**
2010				
Operating revenues	$ 2,535	$ 2,372	$ 2,962	$ 2,321
Operating income	494	440	753	367
Income from continuing operations	191	181	365	130
Net income	190	180	365	128
Net income attributable to controlling interests	190	180	361	125
Common stock data				
Basic and diluted earnings per common share				
Income from continuing operations attributable to controlling interests, net of tax	0.67	0.62	1.23	0.43
Net income attributable to controlling interests	0.67	0.62	1.23	0.42
Dividends declared per common share	0.620	0.620	0.620	0.620
Market price per share				
High	41.35	40.69	44.82	45.61
Low	37.04	37.13	38.96	43.08

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. Typically, weather conditions in our service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to our customers. As a result, our overall operating results may fluctuate substantially on a seasonal basis.

In the third quarter of 2011, we determined the fair value of the CVOs based on the purchase price in a negotiated settlement agreement. As a result, we recognized $50 million of expense, net of tax, related to the change in the CVOs' fair market value. See Note 16 for additional information.

During the fourth quarter of 2011, we recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

PEC

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,133**	**$ 1,060**	**$ 1,332**	**$ 1,003**
Operating income	**228**	**192**	**329**	**136**
Net income	**131**	**107**	**199**	**79**
Net income attributable to controlling interests	**131**	**107**	**199**	**79**
2010				
Operating revenues	$ 1,263	$ 1,117	$ 1,414	$ 1,128
Operating income	266	196	402	207
Net income	136	111	236	119
Net income attributable to controlling interests	138	112	234	119

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. Typically, weather conditions in PEC's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

PEF

Summarized quarterly financial data was as follows:

(in millions)	First	Second	Third	Fourth
2011				
Operating revenues	**$ 1,032**	**$ 1,193**	**$ 1,414**	**$ 730**
Operating income (loss)	**216**	**234**	**361**	**(113)**
Net income (loss)	**102**	**113**	**203**	**(104)**
2010				
Operating revenues	$ 1,270	$ 1,252	$ 1,543	$ 1,189
Operating income	222	244	344	149
Net income	102	119	180	52

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. Typically, weather conditions in PEF's service territories directly influence the demand for electricity and affect the price of energy commodities necessary to provide electricity to its customers. As a result, its overall operating results may fluctuate substantially on a seasonal basis.

During the fourth quarter of 2011, PEF recorded $288 million to be refunded to customers through the fuel clause in accordance with the 2012 settlement agreement. This was recognized as a reduction in operating revenues. See Note 8C for additional information.

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	12/31/2011	End of 2011/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.
4. Report data on a year-to-date basis.

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 Year				
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year				
6	Balance of Account 219 at Beginning of Current Year				
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year				

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges Fuel (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	2,830,907	154,643	2,985,550		
2	41,359	(155,058)	(113,699)		
3	(7,050,966)	190,843	(6,860,123)		
4	(7,009,607)	35,785	(6,973,822)	452,891,011	445,917,189
5	(4,178,700)	190,428	(3,988,272)		
6	(4,178,700)	190,428	(3,988,272)		
7	800,456		800,456		
8	(21,667,726)	(1,803,600)	(23,471,326)		
9	(20,867,270)	(1,803,600)	(22,670,870)	314,398,007	291,727,137
10	(25,045,970)	(1,613,172)	(26,659,142)		

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	12/31/2011	End of 2011/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 (h) 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)	13,242,163,847	13,239,632,607
4	Property Under Capital Leases	198,728,112	198,728,112
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	13,440,891,959	13,438,360,719
9	Leased to Others		
10	Held for Future Use	35,791,002	35,791,002
11	Construction Work in Progress	1,148,814,516	1,148,814,516
12	Acquisition Adjustments	20,040,037	20,040,037
13	Total Utility Plant (8 thru 12)	14,645,537,514	14,643,006,274
14	Accum Prov for Depr, Amort, & Depl	5,066,838,645	5,065,034,155
15	Net Utility Plant (13 less 14)	9,578,698,869	9,577,972,119
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,933,005,607	4,933,005,607
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	134,565,254	132,760,764
22	Total In Service (18 thru 21)	5,067,570,861	5,065,766,371
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	-732,216	-732,216
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,066,838,645	5,065,034,155

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	12/31/2011	End of 2011/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
	1,804,490				14
	726,750				15
					16
					17
					18
					19
					20
	1,804,490				21
	1,804,490				22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
	1,804,490				33

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	75,539	12,347,686
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	75,539	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	168,406,133	96,427,384
9	In Reactor (120.3)	105,710,022	20,819
10	SUBTOTAL (Total 8 & 9)	274,116,155	
11	Spent Nuclear Fuel (120.4)		46,879,386
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	80,115,391	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	194,076,303	
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	12/31/2011	End of 2011/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	12,343,917	79,308	3
			4
			5
		79,308	6
			7
	12,343,917	252,489,600	8
	105,730,841		9
		252,489,600	10
		46,879,386	11
			12
-7,090	8,003,614	72,118,867	13
		227,329,427	14
			15
			16
			17
			18
			19
			20
			21
			22

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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 202 Line No.: 3 Column: e

$12,343,917 transferred to 120.2

Schedule Page: 202 Line No.: 8 Column: e

$12,343,917 transferred to 120.1

Schedule Page: 202 Line No.: 9 Column: e

$46,879,386 discharged to 120.4
$58,851,455 transferred to 120.2

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

$8,003,614 is the cost of canisters for dry spent fuel storage

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	8,450,028	
4	(303) Miscellaneous Intangible Plant	130,846,355	14,572,958
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	139,296,383	14,572,958
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	5,530,632	919,457
9	(311) Structures and Improvements	405,242,083	10,535,985
10	(312) Boiler Plant Equipment	2,002,441,702	-11,014,031
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	508,612,034	26,549,339
13	(315) Accessory Electric Equipment	261,893,136	7,337,938
14	(316) Misc. Power Plant Equipment	32,380,125	2,369,656
15	(317) Asset Retirement Costs for Steam Production	9,768,575	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	3,225,868,287	36,698,344
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	73,547	
19	(321) Structures and Improvements	239,533,190	39,034,630
20	(322) Reactor Plant Equipment	298,964,575	3,628,941
21	(323) Turbogenerator Units	95,486,285	1,821,189
22	(324) Accessory Electric Equipment	184,564,615	971,184
23	(325) Misc. Power Plant Equipment	50,002,289	1,392,257
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	868,624,501	46,848,201
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	18,986,760	726
38	(341) Structures and Improvements	224,334,858	-24,878,415
39	(342) Fuel Holders, Products, and Accessories	137,262,856	764,269
40	(343) Prime Movers	1,500,054,560	127,247,763
41	(344) Generators	340,213,770	1,381,177
42	(345) Accessory Electric Equipment	159,505,606	12,763,961
43	(346) Misc. Power Plant Equipment	45,346,545	-2,148,979
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	2,425,704,955	115,130,502
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	6,520,197,743	198,677,047

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

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
			8,450,028		3
			145,419,313		4
			153,869,341		5
					6
					7
			6,450,089		8
949,494			414,828,574		9
15,229,114	-4,010,118		1,972,188,439		10
					11
7,057,964			528,103,409		12
552,235	92,101		268,770,940		13
56,286	747,203		35,440,698		14
			9,768,575		15
23,845,093	-3,170,814		3,235,550,724		16
					17
			73,547		18
1,205,508	-810,781		276,551,531		19
2,951,962			299,641,554		20
652,937			96,654,537		21
3,309,161			182,226,638		22
12,031,472	-747,203		38,615,871		23
					24
20,151,040	-1,557,984		893,763,678		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
	-701,045		18,286,441		37
240,985			199,215,458		38
-9,867,264			147,894,389		39
93,103,425	-169,951		1,534,028,947		40
5,481,920			336,113,027		41
463,763			171,805,804		42
36,408			43,161,158		43
					44
89,459,237	-870,996		2,450,505,224		45
133,455,370	-5,599,794		6,579,819,626		46

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	103,577,034	5,976,254
49	(352) Structures and Improvements	32,156,330	1,250,088
50	(353) Station Equipment	688,292,520	53,324,838
51	(354) Towers and Fixtures	66,260,759	276,347
52	(355) Poles and Fixtures	551,063,016	36,943,122
53	(356) Overhead Conductors and Devices	354,931,302	40,541,638
54	(357) Underground Conduit	32,127,093	3,503
55	(358) Underground Conductors and Devices	73,053,758	
56	(359) Roads and Trails	3,133,471	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,904,595,283	138,315,790
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	38,052,813	6,488,546
61	(361) Structures and Improvements	26,724,913	1,180,183
62	(362) Station Equipment	552,898,563	29,465,028
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	527,683,989	25,283,233
65	(365) Overhead Conductors and Devices	600,778,569	22,222,355
66	(366) Underground Conduit	237,706,742	12,828,547
67	(367) Underground Conductors and Devices	549,483,044	26,861,425
68	(368) Line Transformers	543,073,058	18,891,584
69	(369) Services	498,471,334	8,043,193
70	(370) Meters	124,929,931	2,553,962
71	(371) Installations on Customer Premises	3,038,858	-46,881
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	306,633,848	10,044,538
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,009,475,662	163,815,713
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	11,714,258	
87	(390) Structures and Improvements	114,152,917	6,173,112
88	(391) Office Furniture and Equipment	21,229,815	2,520,035
89	(392) Transportation Equipment	116,798,161	10,019,475
90	(393) Stores Equipment	2,817,367	112,411
91	(394) Tools, Shop and Garage Equipment	16,718,827	875,744
92	(395) Laboratory Equipment	688,636	8
93	(396) Power Operated Equipment	4,710,480	979,184
94	(397) Communication Equipment	52,090,618	6,055,694
95	(398) Miscellaneous Equipment	10,620,899	-1,229,707
96	SUBTOTAL (Enter Total of lines 86 thru 95)	351,541,978	25,505,956
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	1,974,239	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	353,516,217	25,505,956
100	TOTAL (Accounts 101 and 106)	12,927,081,288	540,887,464
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	12,927,081,288	540,887,464

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
3,158			109,550,130		48
-1,017	-151,635		33,255,800		49
4,839,611	-1,028,322		735,749,425		50
17,070			66,520,036		51
3,108,431			584,897,707		52
2,910,067			392,562,873		53
			32,130,596		54
			73,053,758		55
			3,133,471		56
					57
10,877,320	-1,179,957		2,030,853,796		58
					59
			44,541,359		60
6,111	30,398		27,929,383		61
3,442,546	1,162,905		580,083,950		62
					63
794,488			552,172,734		64
6,670,730			616,330,194		65
317,530			250,217,759		66
4,576,708			571,767,761		67
8,215,767			553,748,875		68
2,231,005			504,283,522		69
245	-13,346		127,470,302		70
-77,831			3,069,808		71
					72
2,040,668			314,637,718		73
					74
28,217,967	1,179,957		4,146,253,365		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			11,714,258		86
443,636	417,284		120,299,677		87
3,342,050	-253,451		20,154,349		88
12,470,427			114,347,209		89
93,192			2,836,586		90
7,118,767			10,475,804		91
62,895			625,749		92
5,763			5,683,901		93
26,046,849			32,099,463		94
765,948			8,625,244		95
50,349,527	163,833		326,862,240		96
					97
			1,974,239		98
50,349,527	163,833		328,836,479		99
222,900,184	-5,435,961		13,239,632,607		100
					101
					102
					103
222,900,184	-5,435,961		13,239,632,607		104

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 204 Line No.: 104 Column: b

Certain balances for 2010 have been reclassified to conform to the 2011 presentation.

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
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10					
11					
12					
13					
14					
15					
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39					
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41					
42					
43					
44					
45					
46					
47	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	12/31/2011	End of 2011/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	12/2022	1,046,211
3	PERRY - FLORIDA STATE LINE	12/92	12/2022	1,808,764
4	HIGH SPRINGS - JASPER - FLORIDA STATE LINE	03/96	12/2022	2,584,486
5	BELCHER ROAD SUBSTATION	05/96	12/2017	267,012
6	LYBASSE PROPERTY - LEVY COUNTY	12/07	12/2018	27,667,950
7	SUWANNEE LAND	12/09	06/2016	701,045
8	OTHER LAND AND RIGHTS <$250K EACH	07/90		962,673
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	PERRY - OTHER PROPERTY	07/90	12/2022	752,861
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
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42				
43				
44				
45				
46				
47	Total			35,791,002

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	12/31/2011	End of 2011/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 $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	60LX8D LAND - Levy BASELOAD Land, Long Lead Time & Pre-Construction	195,014,098
2	60LU1D STEAM GENERATOR MASTER	404,254,006
3	60LU1D NPC EPU	261,791,626
4	60MW8D CR3 CONTAINMENT REPAIR	73,047,040
5	60KK8D 2210S1 CENTRAL FL	23,995,347
6	60LU1D SPENT FUEL DRY CASK	22,510,912
7	60GB9D CR3 LICENSE RENEWAL MAS	17,603,948
8	60MU3D CR3 ISFSI	11,337,026
9	60KK8D 2210S2 CENTRAL FL	8,291,871
10	60KK8D_2006D1_DISSTON-TRANSF	7,881,555
11	60KK8D 2147T1 APAL-ST GEO	7,780,266
12	60731 CR COAL YARD FACILITY	6,108,164
13	60LU1D HOT LEG ALLOY 600 MITIG	5,962,552
14	60KK8D 1858T1BRONSON-CHIEFLAND	4,896,004
15	60KK8D_2162T3_HOLOPAW-FP&L	3,871,732
16	60CR5CRP4 GSU REPLACEMENT	3,746,330
17	60MQ6D SG COMMERCIAL AMI	3,671,732
18	60KK8D 2054T1 QUINCY HAVANA	3,329,030
19	60845D - FL DISASTER RECOVERY	3,243,570
20	98WSD-60-D41-TELEC COMM	3,176,616
21	60KK8D_2162T1_WLXFLINE STRUC	2,737,869
22	60KK8D 1005T4 BOGGY MRSH-GIFF	2,679,968
23	60034D 2125D2 WORLD GATEWAY	2,553,792
24	60KK8D 2013S1 LECANTO SUB	2,256,902
25	60034D-1767D1 PINELLAS WATER	2,181,364
26	60KK8D_1858S1CHIEFLAND SUB	2,092,506
27	60KK8-1862S1 QUINCY TRANSF	2,025,966
28	60GB9D ZTEF RCP-1B MOTR REWIND	1,959,905
29	60KK8D_2162T2_CANOE-HOLOPAW	1,925,967
30	60KK8D 2165S1 CENTRAL FL SOUTH	1,878,927
31	60KK8D_2225T1_KATHLEEN-ZEPH	1,838,785
32	60034D 1093D1 CURRY FORD TRNSF	1,824,239
33	CP HEC PB4B FILTER HOUSE REPL	1,531,931
34	60CR9CRP4 NEW ASH LANDFILL	1,407,701
35	CP IC P5A FREE TURBINE EXCH	1,249,197
36	60GB9D CC CHILLER REPLACEMENT	1,125,536
37	60440 MADISON OC CONTRUCT	1,088,600
38	60CR1CRP4 RAT TRANSFORMER	1,086,304
39	60GB9D RWP IMP - EDG LOAD RED	1,044,077
40	Other Minor	42,811,555
41		
42		
43	TOTAL	1,148,814,516

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Florida Power Corporation	(1) X An Original (2) _ A Resubmission	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 216 Line No.: 1 Column: a

The Levy Baseload Land, Long Lead Time & Pre-Construction Project is reduced by $532,973,005 related to the accelerated recovery of qualifying project cost under the FPSC Nuclear Cost Recovery Rule.

Schedule Page: 216 Line No.: 3 Column: a

The NPC EPU Project is reduced by $21,799,175 related to the accelerated recovery of qualifying project cost under the FPSC Nuclear Cost Recovery Rule.

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	4,791,009,765	4,791,009,765		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	336,548,951	336,548,951		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-405,265	-405,265		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	6,291,334	6,291,334		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock - Oil & Rail Cars	642,597	642,597		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	343,077,617	343,077,617		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	222,666,672	222,666,672		
13	Cost of Removal	56,968,983	56,968,983		
14	Salvage (Credit)	83,497,739	83,497,739		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	196,137,916	196,137,916		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Transfers/Adjustments	-4,943,859	-4,943,859		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,933,005,607	4,933,005,607		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	1,370,207,890	1,370,207,890		
21	Nuclear Production	581,741,408	581,741,408		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	737,604,523	737,604,523		
25	Transmission	525,044,666	525,044,666		
26	Distribution	1,641,233,873	1,641,233,873		
27	Regional Transmission and Market Operation				
28	General	77,173,247	77,173,247		
29	TOTAL (Enter Total of lines 20 thru 28)	4,933,005,607	4,933,005,607		

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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

In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as Other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1. The amount of the adjustment for 2010 is $65,840,613.

Schedule Page: 219 Line No.: 12 Column: c

The book cost of plant retired of $222,666,672 reconciles to that retired of $222,900,184 as shown on pages 204-207, column 9d with the following exceptions:

Assets that do not amortize to 108:

Account 398 $117,263
Account 398.1 $108,122
Account 342.9 $ 4,969

Non-depreciable Property:

Account 350 $ 3,158

Subtotal All $233,512

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6				
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9				
10				
11				
12				
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41				
42	Total Cost of Account 123.1 $ 0		TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	350,104,163	357,584,860	
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)	157,998,527	124,697,007	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	92,900,562	137,143,377	Power Supply
8	Transmission Plant (Estimated)	3,738,107	12,671,423	Transmission
9	Distribution Plant (Estimated)	15,127,194	15,120,772	Customer Service
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,710,743	3,014,704	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	271,475,133	292,647,283	
13	Merchandise (Account 155)	402,450		Customer Service
14	Other Materials and Supplies (Account 156)		526,917	Customer Service
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	8,606,921	8,603,207	Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	630,588,667	659,362,267	

Schedule Page: 227 Line No.: 12 Column: b

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,700,000. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $5,856,480. Co-owned inventory accounts include Crystal River Unit 3 valued at $4,003,335 and Intercession City, Siemens Unit 11 valued at $1,853,145 at the end of 2010.

Account 154 Plant Materials and Operating Supplies - Assigned to Other, represents inventory for Telecommunication and Corporate facilities that cannot be readily assigned to a specific primary function.

Schedule Page: 227 Line No.: 12 Column: c

Account 154 Plant Materials and Operating Supplies includes an Inventory reserve account, credit balance of $1,700,000. Current reserve levels are sufficient based on current inventory reviews.

Account 154 Plant Materials and Operating Supplies is a net balance and excludes the co-owned inventory balance of $6,145,732. Co owned inventory accounts include Crystal Riever Unit 3 valued at $4,268,509 and Intercession City, Siemens Unit 11 valued at $1,877,223 at the end of 2011.

Account 154 Plant Materials and Operating Supplies - Assigned to Other, represents inventory for Telecommunication and Corporate facilities that cannot be readily assigned to a specific primary function.

Schedule Page: 227 Line No.: 14 Column: c

Account 156- Other Materials and Supplies Material reclassed from account 155 during 2011.

Schedule Page: 227 Line No.: 16 Column: b

Account 163 Stores Expense Undistributed - Allocations accounts were charged with $1,069,727 and credited with $600,128 for a net charge of $469,599 during 2010. These charges to operation, maintenance and capital accounts were to record various inventory adjustments for 2010.

Schedule Page: 227 Line No.: 16 Column: c

Account 163 Stores Expense Undistributed - Allocations accounts were charged with $2,149,835 and credited with $2,576,608 for a net credit of $426,773 during 2011. These charges to operations, maintenance and capital accounts were to record various inventory adjustments for 2011.

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	321,889.00	4,829,278	124,141.00	281,600
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	28,588.00	695,888		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Southern Company	12.00			
23					
24					
25					
26					
27					
28	Total	12.00			
29	Balance-End of Year	293,289.00	4,133,390	124,141.00	281,600
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	6,686.00		3,343.00	
37	Add: Withheld by EPA			47.00	
38	Deduct: Returned by EPA				
39	Cost of Sales	1,695.00			
40	Balance-End of Year	4,991.00		3,390.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains	1,695.00	4,818		
46	Losses				

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	12/31/2011	End of 2011/Q4

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.

2013 No. (f)	2013 Amt. (g)	2014 No. (h)	2014 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
124,141.00	281,600	124,141.00	281,600	3,097,666.00		3,791,978.00	5,674,078	1
								2
								3
				119,141.00		119,141.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						28,588.00	695,888	18
								19
								20
								21
						12.00		22
								23
								24
								25
								26
								27
						12.00		28
124,141.00	281,600	124,141.00	281,600	3,216,807.00		3,882,519.00	4,978,190	29
								30
								31
								32
								33
								34
								35
3,343.00				67,600.00		80,972.00		36
47.00		3,390.00		25,625.00		29,109.00		37
								38
				1,695.00		3,390.00		39
3,390.00		3,390.00		91,530.00		106,691.00		40
								41
								42
								43
								44
				1,695.00	304	3,390.00	5,122	45
								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	12/31/2011	End of 2011/Q4

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.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2012 No. (d)	2012 Amt. (e)
1	Balance-Beginning of Year	49,429.00	15,966,277	26,094.00	5,303,425
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	2,500.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Shady Hills	267.00			
10	Southern Company	133.00			
11					
12					
13					
14					
15	Total	400.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	17,451.00	5,449,651		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Southern Company	22.00			
23					
24					
25					
26					
27					
28	Total	22.00			
29	Balance-End of Year	34,856.00	10,516,626	26,094.00	5,303,425
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				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

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.

2013		2014		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
1,325.00	3,790,050	950.00	2,655,675			77,798.00	27,715,427	1
								2
								3
						2,500.00		4
								5
								6
								7
								8
						267.00		9
						133.00		10
								11
								12
								13
								14
						400.00		15
								16
								17
						17,451.00	5,449,651	18
								19
								20
								21
						22.00		22
								23
								24
								25
								26
								27
						22.00		28
1,325.00	3,790,050	950.00	2,655,675			63,225.00	22,265,776	29
								30
								31
								32
								33
								34
								35
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								45
								46

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report 2011/Q4
FOOTNOTE DATA			

Schedule Page: 229 Line No.: 29 Column: f

Assumes EPA will return all forward-vintage, CAIR program allowances existing in compliance accounts prior to stay of Cross-State Air Pollution Rule (CSAPR) in December of 2011.

Schedule Page: 229 Line No.: 29 Column: h

Assumes EPA will return all forward-vintage, CAIR program allowances existing in compliance accounts prior to stay of Cross-State Air Pollution Rule (CSAPR) in December of 2011.

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	12/31/2011	End of 2011/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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Storm Extraordinary Property Loss					
2	Wholesale (FERC letter dated					
3	1/7/2005. Docket No. AC05-12-000					
4	amortization expenses consistent					
5	with recovery in rates.)	5,098,978		4073701	3,008,803	2,090,175
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	5,098,978			3,008,803	2,090,175

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
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43						
44						
45						
46						
47						
48						
49	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	12/31/2011	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22					
23					
24					
25					
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39					
40					

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

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 $100,000 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	221,156,363	13,045,147	4101000	3,568,964	230,632,546
2	as temporary differences occur.					
3						
4	Load Control Switches - Investment	19,041,664	6,728,622	1823320	2,655,615	23,114,671
5	Load Control Switches - Amortization	(8,334,800)	1,342,932	9080120	3,766,295	-10,758,163
6						
7	Interest on Tax Deficiency	5,153,012	23,606,304	4310024	27,562,131	1,197,185
8						
9	Deferred Fuel Expense -Wholesale	5,046,747	3,916,530	5572002	8,071,017	892,260
10	Deferred Fuel Expense - Current Year	227,391,533	175,217,176	5572002	236,912,233	165,696,476
11	Deferred Fuel Expense - Prior Year		219,326,886	5572002	60,501,165	158,825,721
12	Deferred Capacity Expense - Current Year		14,660,426	5572001	14,660,426	
13						
14	Accrued Environmental Cost Recovery	13,357,794	6,407,235	2284800	14,903,874	4,861,155
15						
16	Florida Minimum Pension Liability	526,740,283	192,687,561	2283151-70	51,441,267	667,986,577
17						
18	Regulatory Asset Derivative MTM Oil	383,967,786	296,307,018	2543015-17	172,131,507	508,143,297
19						
20	Regulatory Asset - FAS 143 Asbestos	4,541,911	1,519,168	4074002		6,061,079
21	Regulatory Asset - FAS 143 Landfill	5,879,746	473,377	4074002		6,353,123
22						
23	Deferred Levy - 2010 Regulatory Asset	237,271,498	26,169,435	4073005	86,169,437	177,271,496
24	Deferred Levy Nuclear - Current Year		11,487,820	4073005	11,487,820	
25	Deferred Levy Nuclear - Prior Year	6,618,292			6,618,292	
26	Deferred CR3 NCR - Current Year	145,292	4,108,425	4073005	4,253,717	
27	Deferred CR3 NCR - Prior Year		100,418	4073005	100,418	
28						
29	Regulatory Asset - 2009 Pension	33,805,589				33,805,589
30						
31	Rate Case Expense Regulatory Asset	1,949,803	44,494	4073702	649,934	1,344,363
32						
33	Regulatory Asset - Cost of Removal	65,840,613	254,293,742	4074550	9,734,355	310,400,000
34	Regulatory Asset - Depreciation		11,681,226	4074550		11,681,226
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	1,749,573,126	1,263,123,942		715,188,467	2,297,508,601

Schedule Page: 232 Line No.: 33 Column: b

In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recognize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its 2010 FERC Form 1.

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	12/31/2011	End of 2011/Q4

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 $100,000, 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	487,181	21,514,025	Various	21,698,633	302,573
2	Southern Company Capacity	803,433				803,433
3	Zephyrhills	400,000			400,000	
4	FL Gas Reimbursable Project	264,139	1,431,390	Various	1,656,338	39,191
5	FL Rate Case	6,077	673,294	Various	134,575	544,796
6	UCF Generator Project	23,823	700,226	Various	316,239	407,810
7	SECI - Interconnection Upgrade	9,464,044	453,597	Various	123,637	9,794,004
8	Vacation Pay Accrual	2,577,333	2,648,812	242	2,577,333	2,648,812
9	Smart Grid Deferred Costs	6,006,710	13,990,856	Various	6,193,870	13,803,696
10	Smart Grid Reimbursement	-5,972,762	12,753,664	Various	20,493,431	-13,712,529
11	Labor Accrual	4,846,132	67,992,959	242	67,174,493	5,664,598
12	Worker's Comp	22,636,915	1,697,639	Various	1,099,860	23,234,694
13	Int on Tax Deficiency-LT Asset	2,926,619		Various	2,926,619	
14	Coal Mine Safety	364,261	190,033	Varios		554,294
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	44,833,905				44,085,372

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	12/31/2011	End of 2011/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	61,208,899	39,016,536
3	LIFE/MEDICAL BENEFITS	126,798,203	141,130,699
4	UNAMORTIZED INVESTMENT TAX CREDIT	2,088,647	1,578,299
5	REGULATORY LIABILITY	8,430,015	7,263,597
6	NUCLEAR DECOMMISSIONING	92,373,838	83,549,492
7	Other	327,912,275	646,408,280
8	TOTAL Electric (Enter Total of lines 2 thru 7)	618,811,877	918,946,903
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)	618,811,877	918,946,903

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	12/31/2011	End of 2011/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	Cummulative Preferred Stock	4,000,000		
4	4.00% Series		100.00	104.25
5	4.60% Series		100.00	103.25
6	4.75% Series		100.00	102.00
7	4.40% Series		100.00	102.00
8	4.58% Series		100.00	101.00
9	Cumulative Preferred Stock	5,000,000		
10	Preference Stock	1,000,000	100.00	
11	Total Preferred Stock	10,000,000		
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13				
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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	12/31/2011	End of 2011/Q4

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
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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	12/31/2011	End of 2011/Q4

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 in 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	1,359,992,013
23	Other Miscellaneous adjustments	45,211
24	Payroll taxes associated with stock option exercises	1,334,279
25	Misc PIC - Stock Options	655,780
26	Misc PIC - Performance Share Sub Plan (PSSP)	14,831,788
27	Misc PIC - Restricted Stock Units (RSU)	24,465,618
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	1,402,648,736

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	12/31/2011	End of 2011/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
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19		
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21		
22	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	12/31/2011	End of 2011/Q4

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 - 4.8%	425,000,000	4,585,299
4			1,513,000 D
5	First Mortgage Bonds - 5.9%	225,000,000	3,013,280
6			571,500 D
7	First Mortgage Bonds - 5.1%	300,000,000	3,473,110
8			594,000 D
9	Medium Term Note - 6.75%	150,000,000	5,528,498
10			436,500 D
11	Pollution Control Bonds (Citrus) 2002A	108,550,000	2,356,705
12			D
13	Pollution Control Bonds (Citrus) 2002B	100,115,000	2,081,983
14			D
15	Pollution Control Bonds (Citrus) 2002C	32,200,000	756,175
16			D
17	RCA - 5 Year		1,009,474
18	RCA - 3 Year		3,768,106
19	First Mortgage Bonds - 6.35%	500,000,000	6,708,137
20			660,000 D
21	First Mortgage Bonds - 5.80%	250,000,000	2,959,477
22			672,500 D
23	First Mortgage Bonds - 5.65%	500,000,000	5,559,462
24			1,805,000 D
25	First Mortgage Bonds - 6.40%	1,000,000,000	13,136,457
26			4,220,000 D
27	First Mortgage Bonds - 4.55%	250,000,000	2,820,764
28			142,500 D
29	First Mortgage Bonds - 5.65%	350,000,000	4,690,119
30			1,459,500 D
31	First Mortgage Bonds - 3.10% - Auth # PSC-10-0717-FOF-EI (12/8/10)	300,000,000	3,467,458
32			612,000 D
33	TOTAL	4,790,865,000	82,212,661

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	12/31/2011	End of 2011/Q4

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.
7/18/01	7/15/11	7/18/01	7/15/11		10,806,250	1
						2
2/21/03	3/1/13	2/21/03	3/1/13	425,000,000	20,400,000	3
						4
2/21/03	2/15/33	2/21/03	2/15/33	225,000,000	13,275,000	5
						6
11/21/03	12/1/15	11/21/03	12/1/15	300,000,000	15,300,000	7
						8
2/13/98	2/1/28	2/13/98	2/1/28	150,000,000	10,125,000	9
						10
8/20/02	1/01/27	8/20/02	1/01/27	108,550,000	509,540	11
						12
7/24/02	1/01/22	7/24/02	1/01/22	100,115,000	471,870	13
						14
8/13/02	1/01/18	8/13/02	1/01/18	32,200,000	151,554	15
						16
3/28/05	10/15/10	3/28/05	10/15/10			17
10/15/10	10/15/13	10/15/10	10/15/13			18
9/12/07	9/15/37	9/12/07	9/15/37	500,000,000	32,068,629	19
						20
9/12/07	9/15/17	9/12/07	9/15/17	250,000,000	14,915,689	21
						22
6/15/08	6/15/18	6/15/08	6/15/18	500,000,000	27,801,293	23
						24
6/15/08	6/15/38	6/15/08	6/15/38	1,000,000,000	63,709,946	25
						26
3/22/10	4/01/20	3/22/10	4/01/20	250,000,000	11,439,621	27
						28
3/22/10	4/01/40	3/22/10	4/01/40	350,000,000	19,775,000	29
						30
8/15/11	8/15/21	8/15/11	8/15/21	300,000,000	5,127,069	31
						32
				4,490,865,000	245,876,461	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	12/31/2011	End of 2011/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)	314,398,007
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	152,916,930
11		
12	Deductions Recorded on Books Not Deducted for Return	1,586,155,273
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	2,184,185,309
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-130,715,099
28	Show Computation of Tax:	
29	Provision for Federal Income Tax at 35%	-45,750,285
30	True Up Entries and Other Tax Benefits	-14,133,165
31	Total Federal Income Tax Provision (409120F - 409220F) True Up Entries	-59,883,450
32		
33		
34		
35		
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42		
43		
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	12/31/2011	End of 2011/Q4

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	-57,681,001		-59,883,450	-105,370,166	
3	FICA			25,411,988	25,411,988	
4	Unemployment	12,498		291,294	293,668	
5	Special Fuel Tax					
6	Excise Tax					
7	Highway Use			39,565	39,565	
8	Payroll Tax	1,989,704		217,355		
9	SUBTOTAL	-55,678,799		-33,923,248	-79,624,945	
10						
11	STATE TAXES					
12	Income	-11,363,351		4,862,811	3,602,117	
13	Income Tax Subsidiary					
14	Gross Receipts	8,574,310		104,728,112	106,270,801	
15	Unemployment	15,402		1,264,671	1,259,857	
16	Intangibles					
17	Regulatory Assessment	1,786,762		3,118,576	3,274,763	
18	Sales Tax-Company Use	37,330		220,914	257,774	
19	SUBTOTAL	-949,547		114,195,084	114,665,312	
20						
21	COUNTY & LOCAL TAXES					
22	Property-County & Local	843,790		122,181,038	122,914,983	
23	FL Privilege License					
24	Franchise-Local	8,321,329		100,421,873	102,097,560	
25						
26						
27	Adj-Use Tax on Purchases					
28	SUBTOTAL	9,165,119		222,602,911	225,012,543	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-47,463,227		302,874,747	260,052,910	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-12,194,285		-65,117,214			5,233,764	2
		21,906,480			3,505,508	3
10,124					291,294	4
						5
						6
		39,565				7
2,207,059					217,355	8
-9,977,102		-43,171,169			9,247,921	9
						10
						11
-10,102,657		8,345,732			-3,482,921	12
						13
7,031,621		104,728,112				14
20,216					1,264,671	15
						16
1,630,575		3,118,576				17
470		220,914				18
-1,419,775		116,413,334			-2,218,250	19
						20
						21
109,845		122,181,038				22
						23
6,645,642		100,421,873				24
						25
						26
						27
6,755,487		222,602,911				28
						29
						30
						31
						32
						33
						34
						35
						36
						37
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						39
						40
-4,641,390		295,845,076			7,029,671	41

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) 12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 262 Line No.: 27 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.

Taxes Accrued, P. 112, Line 37	(47,287,561)	(4,594,856)
State Sales Tax on Purchases	(161,344)	(35,564)
County Sales Tax on Purchases	(14,322)	(10,971)
	(47,463,228)	(4,641,391)

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	12/31/2011	End of 2011/Q4

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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	5,414,516			4114001	1,323,000	
6							
7							
8	TOTAL	5,414,516				1,323,000	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
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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	12/31/2011	End of 2011/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
4,091,516	27 Years		5
			6
			7
4,091,516			8
			9
			10
			11
			12
			13
			14
			15
			16
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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	12/31/2011	End of 2011/Q4

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 $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Wholesale Deposits - SECI	1,950,000	131		90,000	2,040,000
2	Wholesale Deposits - Other	247,305	253	145,098	60,000	162,207
3	Wholesale Deposits - FMPA	1,500,000	131	1,500,000		
4	PTC Fiber 400 Indemnification	5,862,677	242	2,943,402	934,389	3,853,664
5	12K Basket Upgrade	120,000	107	21,174,271	21,054,271	
6	Cable and Other Deposits	961,621	131, 242	715,979	731,101	976,743
7	Deferred Rent Expense	516,290	242, 931		69,598	585,888
8	Franchise Settlements	1,312,000	131	74,000		1,238,000
9	PEP Lease Incentives	3,067,349	242	148,852		2,918,497
10	Feasibility Study	335,130	186	99,128	34,400	270,402
11	LT Service Agreement - Hines	3,238,800	107,554,553	47,990,386	47,177,086	2,425,500
12	LT Service Agreement - Bartow		107,554,553	12,355,692	13,646,361	1,290,669
13	CR3 Capacity Factor		242, 555	17,358,384	33,453,443	16,095,059
14	Interest on Tax Deficiency-LT LIA		171, 186		6,743,500	6,743,500
15	Joint Owner	-73,905	various	29,453,908	28,325,837	-1,201,976
16	SmartGrid		various	73,977,504	73,977,504	
17	Various		various	4,523,297	4,523,297	
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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40						
41						
42						
43						
44						
45						
46						
47	TOTAL	19,037,267		212,459,901	230,820,787	37,398,153

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	12/31/2011	End of 2011/Q4

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	3,757,590		
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	3,757,590		
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)	3,757,590		
18	Classification of TOTAL			
19	Federal Income Tax	3,221,835		
20	State Income Tax	535,755		
21	Local Income Tax			

NOTES

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
						3,757,590	4
							5
							6
							7
						3,757,590	8
							9
							10
							11
							12
							13
							14
							15
							16
						3,757,590	17
							18
						3,221,835	19
						535,755	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	12/31/2011	End of 2011/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	964,138,005	423,409,663	
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	964,138,005	423,409,663	
6	Other			
7	Other			
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	964,138,005	423,409,663	
10	Classification of TOTAL			
11	Federal Income Tax	833,481,106	386,705,473	
12	State Income Tax	130,656,899	36,704,191	
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
7,690,227		409.1&190.1	18,795,288			1,376,442,607	2
							3
							4
7,690,227			18,795,288			1,376,442,607	5
							6
							7
							8
7,690,227			18,795,288			1,376,442,607	9
							10
6,593,760			16,848,026			1,209,932,313	11
1,096,467			1,947,262			166,510,295	12
							13

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: h

Adjustments detail for Account and Amount on Page 275, Line 2, Col. (g) & (h) are as follows:

Electric	409.1	17,711,963
Electric	190.1	1,083,325
		18,795,288

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Regulatory Assets - FAS 109	85,310,907	-3,987,537	
4				
5				
6				
7				
8	Other	612,261,384	37,891,203	395,802
9	TOTAL Electric (Total of lines 3 thru 8)	697,572,291	33,903,666	395,802
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)	697,572,291	33,903,666	395,802
20	Classification of TOTAL			
21	Federal Income Tax	598,153,784	29,028,775	339,369
22	State Income Tax	99,418,507	4,874,891	56,433
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
7,642,976						88,966,346	3
							4
							5
							6
							7
				190.1	66,320,691	716,077,476	8
7,642,976					66,320,691	805,043,822	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
7,642,976					66,320,691	805,043,822	19
							20
6,553,245					56,864,728	690,261,163	21
1,089,731					9,455,963	114,782,659	22
							23

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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 8 Column: i

Adjustments to 283 - Various Accounts

Credits to 283 - Debits to Various Accounts

19010FE	(22,501)
19010FL	(3,742)
19011FE	56,887,229
19011FL	9,459,705
Total	66,320,691

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	12/31/2011	End of 2011/Q4

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 $100,000 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	21,852,574	4111000	3,210,526	186,766	18,828,814
2	Period of Amortization occurs as					
3	temporary differences occur.					
4						
5	Deferred GPIF Penalty	3,009,296	4560096	676,296	647,090	2,980,090
6	Regulatory Liability Fuel	59,134,005	5572002	200,437,475	494,933,571	353,630,101
7	Deferred Fuel Revenue - Current Year		5572002	27,921,093	27,921,093	
8	Deferred Fuel Revenue - Prior Year	8,064,648	5572002	8,064,648		
9	Deferred Capacity Revenue - Cur Yr.	52,813,960	5572001	71,906,350	20,636,323	1,593,933
10	Deferred Capacity Revenue - Pr. Yr.	14,181,129	5572001	52,311,070	52,813,960	14,684,019
11						
12	Deferred Environmental Cost Recovery	45,115,276	4074017	38,019,164	515	7,096,627
13						
14	ARO - SFAS 143 Nuclear Decom	44,863,261	4073002	357,232,460	354,399,385	42,030,186
15	ARO - SFAS 143 Asbestos	3,336,176	4073002	208,950	84,312	3,211,538
16	NDT - Qualified - Unrealized Gains	154,158,896	4073002	81,865,475	73,918,769	146,212,190
17						
18	Auctioned S02 Allowance	1,776,567	4070004	225,143	5,122	1,556,546
19						
20	Regulatory Liability Derivative MTM Oil	13,193,303	1823015	35,688,130	27,293,929	4,799,102
21						
22	Deferred Energy Conservation	11,290,162	9080110	2,501,098	10,626,865	19,415,929
23						
24	Deferred Levy Nuclear - Current Year	58,757,700	4074005	60,602,926	9,446,487	7,601,261
25	Deferred Levy Nuclear - Prior Year		4074005	9,462,817	71,150,533	61,687,716
26	Deferred CR3 Nuclear - Current Year		4074005	139,555	4,612,872	4,473,317
27	Deferred CR3 Nuclear - Prior Year	208,937	4074005	145,292	1,465,114	1,528,759
28						
29	Regulatory Liability Gains & Losses	5,502,073	4211001	68,099,355	66,682,914	4,085,632
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	497,257,963		1,018,717,823	1,216,875,620	695,415,760

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	12/31/2011	End of 2011/Q4

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.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

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	2,463,243,933	2,785,111,187
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	1,183,068,742	1,252,328,092
5	Large (or Ind.) (See Instr. 4)	284,523,762	300,257,974
6	(444) Public Street and Highway Lighting	1,879,376	1,983,892
7	(445) Other Sales to Public Authorities	307,311,346	329,958,448
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	4,240,027,159	4,669,639,593
11	(447) Sales for Resale	239,145,300	348,601,308
12	TOTAL Sales of Electricity	4,479,172,459	5,018,240,901
13	(Less) (449.1) Provision for Rate Refunds	287,939,887	188,823
14	TOTAL Revenues Net of Prov. for Refunds	4,191,232,572	5,018,052,078
15	Other Operating Revenues		
16	(450) Forfeited Discounts	23,602,188	23,587,819
17	(451) Miscellaneous Service Revenues	22,440,885	23,201,167
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	87,917,681	94,423,198
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	43,848,974	94,717,738
22	(456.1) Revenues from Transmission of Electricity of Others		
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	177,809,728	235,929,922
27	TOTAL Electric Operating Revenues	4,369,042,300	5,253,982,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.
				1
19,237,836	20,524,060	1,452,455	1,451,467	2
				3
11,891,809	11,895,890	162,071	161,674	4
3,242,738	3,219,344	2,408	2,481	5
24,882	25,788	1,572	1,621	6
3,199,671	3,259,984	23,640	23,571	7
				8
				9
37,596,936	38,925,066	1,642,146	1,640,814	10
2,762,887	3,690,913	15	19	11
40,359,823	42,615,979	1,642,161	1,640,833	12
				13
40,359,823	42,615,979	1,642,161	1,640,833	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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 300 Line No.: 17 Column: b

Includes revenues of $22,424,669 from service charges billed to customers for establishment of new service, reconnection of service, and transfer of account from one occupant to another.

Schedule Page: 300 Line No.: 17 Column: c

Includes revenues of $23,189,362 from service charges billed to customers for establishment of new service, reconnection of service, and transfer of account from one occupant to another.

Schedule Page: 300 Line No.: 21 Column: b

Includes revenues of: $69,688,168 from Wheeling-Transmission; ($24,554,859) from Retail Unbilled revenue; ($7,757,099) from Wholesale Unbilled revenue; and $5,920,961 from Wheeling Production Ancillary services.

Schedule Page: 300 Line No.: 21 Column: c

Includes revenues of: $67,174,239 from Wheeling-Transmission; $16,655,842 from Retail Unbilled revenue; $3,251,945 from Wholesale Unbilled revenue; ($2,478,146) from Generation Performance Incentive Factor; $8,635,127 from Wheeling Production Ancillary services; and $991,562 from Other Misc Electric 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	12/31/2011	End of 2011/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
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33					
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36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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 Services	19,237,836	2,463,243,933	1,452,455	13,245	0.1280
2						
3	Commercial and Industrial Service	15,134,546	1,467,592,504	164,479	92,015	0.0970
4						
5	Public Street and Highway Lightin	24,882	1,879,376	1,572	15,828	0.0755
6						
7	Other Sales to Public Authorities	3,199,671	307,311,346	23,640	135,350	0.0960
8						
9	Total Sales to Ultimate Customers	37,596,935	4,240,027,159	1,642,146	22,895	0.1128
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
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24						
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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	12/31/2011	End of 2011/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	CITY OF BARTOW	RQ	9	25		
2	CITY OF CHATTAHOOCHEE	RQ	126	5	8	8
3	CITY OF HOMESTEAD	RQ	9	35	30	30
4	CITY OF DORA	RQ	127	19	23	23
5	CITY OF NEW SMYRNA BEACH	RQ	144	25	25	25
6	CITY OF QUINCY	RQ	1	7	72	72
7	CITY OF TALLAHASSEE	RQ	178	11		
8	CITY OF WILLISTON	RQ	124	7	6	6
9	CITY OF WINTER PARK	RQ	191	44	11	
10	FLORIDA MUNICIPAL POWER AGENCY	RQ	107	17	84	84
11	REEDY CREEK IMPROVEMENT DISTRICT	RQ	118	81	9	9
12	SEMINOLE ELECTRIC COOPERATIVE, INC	RQ	106	651	580	580
13	SOUTHEASTERN POWER ADMIN	RQ	65	18		
14	CITY OF GAINSVILLE	RQ	88	52	100	100
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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 s 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 ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,269	671,375	1,309,037		1,980,412	1
31,641	668,648	1,763,213	3,168	2,435,029	2
223,239	5,880,000	10,194,805		16,074,805	3
95,374	1,807,455	5,386,554		7,194,009	4
68,680	3,743,750	3,764,146		7,507,896	5
10,265	195,464	486,832		682,296	6
99,867	-245,419	4,550,250		4,304,831	7
34,579	585,515	2,075,750		2,661,265	8
310,846	4,649,905	12,978,503		17,628,408	9
24,090	1,939,755	1,257,178	17,760	3,214,693	10
290,319	14,802,500	12,754,874	2,883	27,560,257	11
1,302,347	57,452,265	66,023,603	8,135	123,484,003	12
52,142	556,193	2,672,130		3,228,323	13
140,735	12,500,000	6,634,255		19,134,255	14
2,712,393	105,207,406	131,851,130	31,946	237,090,482	
50,494	0	2,189,637	-134,819	2,054,818	
2,762,887	**105,207,406**	**134,040,767**	**-102,873**	**239,145,300**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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						
2						
3						
4						
5	NON-REQUIREMENTS SERVICE					
6	EDF TRADING NORTH AMERICA LLC	OS	10			
7	COBB ELECTRIC MEMBERSHIP	OS	10			
8	CARGILL POWER MARKETS LLC	OS	8			
9	FLORIDA MUNICIPAL POWER AGENCY	OS	105			
10	FLORIDA POWER AND LIGHT COMPANY	OS	81			
11	CITY OF NEW SMYRNA BEACH	OS	104			
12	OGLETHORPE POWER CORPORATION	OS	139			
13	ORLANDO UTILITIES COMMISSION	OS	86			
14	PENNSYLVANIA-NEW JERSEY-MARYLAND					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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,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
					2
					3
					4
					5
693		25,328		25,328	6
		-387		-387	7
		-1,420		-1,420	8
275		13,300		13,300	9
998		43,426		43,426	10
1,778		374,521	-134,819	239,702	11
100		4,225		4,225	12
290		10,688		10,688	13
					14
2,712,393	105,207,406	131,851,130	31,946	237,090,482	
50,494	0	2,189,637	-134,819	2,054,818	
2,762,887	**105,207,406**	**134,040,767**	**-102,873**	**239,145,300**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	INTERCONNECTION, LLC	OS	24			
2	CITY OF HOMESTEAD	OS	82			
3	REEDY CREEK UTILITIES	OS	119			
4	SEMINOLE ELECTRIC					
5	COOPERATIVE INCORPORATED	OS	128			
6	CITY OF TALLAHASSEE	OS	122			
7	THE ENERGY AUTHORITY	OS	175			
8	TAMPA ELECTRIC COMPANY	OS	80			
9	TENNESSEE VALLEY AUTHORITY	OS	138			
10	CITY OF GAINESVILLE	OS	88			
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	12/31/2011	End of 2011/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,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.
1,041		34,696		34,696	1
70		3,043		3,043	2
16,766		598,987		598,987	3
					4
4,614		177,407		177,407	5
250		38,057		38,057	6
13,828		500,561		500,561	7
9,741		365,233		365,233	8
					9
50		1,972		1,972	10
					11
					12
					13
					14
2,712,393	105,207,406	131,851,130	31,946	237,090,482	
50,494	0	2,189,637	-134,819	2,054,818	
2,762,887	**105,207,406**	**134,040,767**	**-102,873**	**239,145,300**	

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) 12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 5 Column: a

Schedule Page: 310.1 Line No.: 11 Column: j

2011 OS Sales for city of New Smyrna Beach includes ($134,819)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	12/31/2011	End of 2011/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	12,199,344	10,143,941
5	(501) Fuel	596,403,549	731,542,862
6	(502) Steam Expenses	26,203,440	18,739,228
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.	-869	
9	(505) Electric Expenses	12,379	1,280
10	(506) Miscellaneous Steam Power Expenses	11,582,189	11,414,866
11	(507) Rents		
12	(509) Allowances	6,145,539	12,438,359
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	652,547,309	784,280,536
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,572,009	5,660,914
16	(511) Maintenance of Structures	1,723,492	1,745,874
17	(512) Maintenance of Boiler Plant	22,874,610	21,361,883
18	(513) Maintenance of Electric Plant	8,354,995	9,340,141
19	(514) Maintenance of Miscellaneous Steam Plant	15,825,147	13,689,432
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	54,350,253	51,798,244
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	706,897,562	836,078,780
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	2,159,236	2,128,437
25	(518) Fuel	1,720,055	1,764,186
26	(519) Coolants and Water	3,811,776	4,744,619
27	(520) Steam Expenses	6,765,007	9,953,089
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	2,634,648	1,111,548
31	(524) Miscellaneous Nuclear Power Expenses	47,852,530	44,099,654
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)	64,943,252	63,801,533
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	10,088,303	11,942,512
36	(529) Maintenance of Structures	4,070,063	2,815,916
37	(530) Maintenance of Reactor Plant Equipment	4,563,067	8,341,542
38	(531) Maintenance of Electric Plant	3,155,749	7,595,524
39	(532) Maintenance of Miscellaneous Nuclear Plant	6,092,914	3,793,713
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	27,970,096	34,489,207
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	92,913,348	98,290,740
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)		
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)		

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	12,610,859	10,310,849
63	(547) Fuel	1,059,481,848	1,248,401,123
64	(548) Generation Expenses	10,151,628	11,173,743
65	(549) Miscellaneous Other Power Generation Expenses	7,439,398	7,960,577
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,089,683,733	1,277,846,292
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	883,281	999,915
70	(552) Maintenance of Structures	933,277	986,278
71	(553) Maintenance of Generating and Electric Plant	21,726,031	17,751,426
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	16,754,417	11,876,228
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	40,297,006	31,613,847
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	1,129,980,739	1,309,460,139
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	828,989,732	870,799,166
77	(556) System Control and Load Dispatching	2,306,959	2,216,139
78	(557) Other Expenses	68,271	72,546
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	831,364,962	873,087,851
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,761,156,611	3,116,917,510
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,509,805	4,714,736
84	(561) Load Dispatching	-1,473	45,139
85	(561.1) Load Dispatch-Reliability	1,250,856	1,349,751
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	975,054	918,444
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,191,750	1,236,898
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	542,778	587,233
90	(561.6) Transmission Service Studies	418	
91	(561.7) Generation Interconnection Studies	514,238	558,153
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	55,338	75,656
94	(563) Overhead Lines Expenses	742,221	395,477
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others		
97	(566) Miscellaneous Transmission Expenses	4,284,886	4,432,497
98	(567) Rents		
99	TOTAL Operation (Enter Total of lines 83 thru 98)	14,065,871	14,313,984
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,417,132	1,548,838
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	44,879	48,530
104	(569.2) Maintenance of Computer Software	107,779	126,686
105	(569.3) Maintenance of Communication Equipment	62,993	66,862
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	6,098,722	5,905,801
108	(571) Maintenance of Overhead Lines	11,104,291	7,587,288
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	7,134,079	5,540,836
111	TOTAL Maintenance (Total of lines 101 thru 110)	25,969,875	20,824,841
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	40,035,746	35,138,825

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	21,596,845	18,745,412
135	(581) Load Dispatching	3,935,740	3,970,166
136	(582) Station Expenses	87,725	59,800
137	(583) Overhead Line Expenses	4,348,598	3,944,535
138	(584) Underground Line Expenses	2,265,737	3,252,074
139	(585) Street Lighting and Signal System Expenses	5,605,131	5,331,590
140	(586) Meter Expenses	8,626,263	8,693,349
141	(587) Customer Installations Expenses	1,438,938	1,231,416
142	(588) Miscellaneous Expenses	19,336,274	17,966,906
143	(589) Rents	812,288	994,222
144	TOTAL Operation (Enter Total of lines 134 thru 143)	68,053,539	64,189,470
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	3,363,785	3,145,275
147	(591) Maintenance of Structures	31,315	6,652
148	(592) Maintenance of Station Equipment	4,646,650	4,622,641
149	(593) Maintenance of Overhead Lines	32,046,627	40,075,991
150	(594) Maintenance of Underground Lines	5,145,758	8,036,949
151	(595) Maintenance of Line Transformers	6,376,608	5,490,339
152	(596) Maintenance of Street Lighting and Signal Systems	420,705	273,424
153	(597) Maintenance of Meters	771,563	731,752
154	(598) Maintenance of Miscellaneous Distribution Plant	11,683,660	15,791,415
155	TOTAL Maintenance (Total of lines 146 thru 154)	64,486,671	78,174,438
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	132,540,210	142,363,908
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	2,100,876	2,314,236
160	(902) Meter Reading Expenses	3,120,749	2,915,195
161	(903) Customer Records and Collection Expenses	27,592,405	27,621,849
162	(904) Uncollectible Accounts	7,928,974	14,806,031
163	(905) Miscellaneous Customer Accounts Expenses	1,453,449	1,231,704
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	42,196,453	48,889,015

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	12/31/2011	End of 2011/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)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	94,769,826	89,479,013
169	(909) Informational and Instructional Expenses	5,781,419	5,230,235
170	(910) Miscellaneous Customer Service and Informational Expenses		-112
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	100,551,245	94,709,136
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	1,441,855	1,145,247
176	(913) Advertising Expenses	10,559	14,583
177	(916) Miscellaneous Sales Expenses	64,336	173,652
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	1,516,750	1,333,482
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	62,192,006	62,245,281
182	(921) Office Supplies and Expenses	20,968,957	22,675,980
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	34,852,979	51,588,583
185	(924) Property Insurance	10,098,812	9,064,897
186	(925) Injuries and Damages	12,898,019	17,392,685
187	(926) Employee Pensions and Benefits	109,341,146	116,606,280
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	345,175	350,069
190	(929) (Less) Duplicate Charges-Cr.	2,236,826	1,826,923
191	(930.1) General Advertising Expenses	1,245,625	1,356,417
192	(930.2) Miscellaneous General Expenses	5,169,736	11,893,778
193	(931) Rents	9,857,010	7,080,811
194	TOTAL Operation (Enter Total of lines 181 thru 193)	264,732,639	298,427,858
195	Maintenance		
196	(935) Maintenance of General Plant	3,464,462	3,348,986
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	268,197,101	301,776,844
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,346,194,116	3,741,128,720

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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)	Average Monthly CP Demand (f)
1	PURCHASED POWER:					
2	SOUTHEASTERN POWER ADM	OS	65	N/A	N/A	N/A
3	AUBURNDALE POWER PARTNERS (1)	OS	COG-Note 1	134	148	141
4	AUBURNDALE POWER PARTNERS (1)	AD	COG			
5	CENTRAL POWER & LIME (1)	OS	COG-Note 1	N/A	N/A	N/A
6	CENTRAL POWER & LIME (1)	AD	COG			
7	CITRUS WORLD (1)	OS	COG-Note 1	N/A	N/A	N/A
8	CITRUS WORLD (1)	AD	COG			
9	LAKE COUNTY (1)	OS	COG-Note 1	11	13	9
10	LAKE COUNTY (1)	AD	COG			
11	LAKE COGEN LIMITED (1)	OS	COG-Note 1	112	122	92
12	LAKE COGEN LIMITED (1)	AD	COG			
13	DADE COUNTY (1)	OS	COG-Note 1	39	54	38
14	DADE COUNTY (1)	AD	COG			
	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	12/31/2011	End of 2011/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)	
							1
24,326				1,184,684		1,184,684	2
646,209			47,989,645	33,186,563		81,176,208	3
					-58,839	-58,839	4
28,454				1,686,548		1,686,548	5
							6
121				6,866		6,866	7
					250	250	8
90,946			8,202,330	2,862,705		11,065,035	9
					3,840	3,840	10
468,480			40,578,072	26,547,450		67,125,522	11
					-437,918	-437,918	12
339,887			15,237,480	16,665,477		31,902,957	13
					-144,335	-144,335	14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	ORANGE COGEN LIMITED (1)	OS	COG-Note 1	69	104	67
2	ORANGE COGEN LIMITED (1)	AD	COG			
3	ORLANDO COGEN LIMITED (1)	OS	COG-Note 1	72	114	95
4	ORLANDO COGEN LIMITED (1)	AD	COG			
5	PASCO COUNTY (1)	OS	COG-Note 1	22	26	20
6	PASCO COUNTY (1)	AD	COG			
7	PCS PHOSPHATE (1)	OS	COG-Note 1	N/A	N/A	N/A
8	PCS PHOSPHATE (1)	AD	COG			
9	PINELLAS COUNTY (1)	OS	COG-Note 1	43	66	44
10	PINELLAS COUNTY (1)	AD	COG			
11	POLK POWER PARTNERS (1)	OS	COG-Note 1	115	123	84
12	POLK POWER PARTNERS (1)	AD	COG			
13	RIDGE GENERATING STATION (1)	OS	COG-Note 1	36	42	32
14	RIDGE GENERATING STATION (1)	AD	COG			
	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	12/31/2011	End of 2011/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.
247,501			34,867,266	11,158,005		46,025,271	1
					14,226	14,226	2
611,913			30,558,589	32,511,696		63,070,285	3
					8,587	8,587	4
182,429			14,796,360	5,749,371		20,545,731	5
					17,643	17,643	6
3,664				151,098		151,098	7
					6,116	6,116	8
361,524			35,221,770	11,322,416		46,544,186	9
					18,173	18,173	10
420,188			62,010,217	15,374,102		77,384,319	11
					14,629	14,629	12
239,772			9,718,202	13,427,931		23,146,133	13
					36,322	36,322	14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

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	12/31/2011	End of 2011/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						
2						
3	INTERCHANGE POWER:					
4	CITY OF CHATTAHOOCHEE	OS	126			
5	CITY OF CHATTAHOOCHEE	AD	126			
6	CALPINE ENERGY SERVICES LLC	OS	170			
7	CALPINE ENERGY SERVICES LLC	AD	170			
8	CARGILL POWER MARKET LLC	OS	NOTE (1)			
9	CONSTELLATION ENERGY					
10	COMMMODITIES GROUP	OS	8 ; 10			
11	DUKE ENERGY CAROLINA LLC	OS	NOTE (1)			
12	EDF TRADING NORTH AMERICA LLC	OS	NOTE (1)			
13	FLORIDA POWER AND LIGHT COMPANY	OS	81; 9			
14	FLORIDA POWER AND LIGHT COMPANY	AD	81; 9			
	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	12/31/2011	End of 2011/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
							2
							3
			151,550			151,550	4
					9,614	9,614	5
31,924				1,749,557		1,749,557	6
					12,474	12,474	7
265,888				16,992,224		16,992,224	8
							9
179,510				8,731,503		8,731,503	10
				6,122		6,122	11
88,511				4,680,557		4,680,557	12
26,863				2,197,088		2,197,088	13
					-535	-535	14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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.

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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	GEORGIA TRANSMISSION CORPORATION	OS	9			
2	FLORIDA MUNICIPAL POWER AGENCY	OS	9			
3	JACKSONVILLE ELECTRIC AUTHORITY	OS	91			
4	J P MORGAN VENTURES					
5	ENERGY CORPORATION	OS	NOTE (1)			
6	CITY OF LAKELAND	OS	92			
7	NEW HOPE POWER PARTNERSHIP	OS	NA			
8	CITY OF NEW SMYRNA BEACH	OS	104			
9	ORLANDO UTILITIES COMMISSION	OS	86			
10	PENNSYLVANIA-NEW JERSEY-MARYLAND					
11	INTERCONNECTION LLC	OS	24			
12	RAINBOW ENERGY MARKETING	OS	NOTE (1)			
13	REEDY CREEK UTILITIES	OS	119			
14	RELIANT ENERGY SERVICES	OS	167			
	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	12/31/2011	End of 2011/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)	
				20,817		20,817	1
412				23,052		23,052	2
				2,404,623		2,404,623	3
							4
38,398				2,232,545		2,232,545	5
2,050				127,100		127,100	6
1,627				88,809		88,809	7
					-134,819	-134,819	8
29,975				1,573,764		1,573,764	9
							10
				6,747		6,747	11
2,922				222,166		222,166	12
1,178				82,369		82,369	13
539,674			17,454,260	39,942,661		57,396,921	14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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)	Average Monthly CP Demand (f)
1	RELIANT ENERGY SERVICES	AD	167			
2	SEMINOLE ELECTRIC					
3	COOPERATIVE INCORPORATED	OS	128			
4	SHADY HILLS POWER COMPANY	OS	6			
5	SHADY HILLS POWER COMPANY	AD	6			
6	SOUTHERN COMPANY SERVICES	OS	111; 10			
7	SOUTHERN COMPANY SERVICES	AD	111; 10			
8	CITY OF TALLAHASSEE	OS	122			
9	THE ENERGY AUTHORITY	OS	175; 10			
10	TAMPA ELECTRIC COMPANY	OS	80; 10; 9			
11	TAMPA ELECTRIC COMPANY	AD	80; 10; 9			
12	MUNICIPAL ELECTRIC					
13	AUTHORITY OF GEORGIA	OS	3			
14	MORGAN STANLEY CAPITAL GROUP	OS	177			
	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	12/31/2011	End of 2011/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.
					29,184	29,184	1
							2
9,301				1,396,964		1,396,964	3
793,752			26,720,320	59,561,933		86,282,253	4
					68,218	68,218	5
2,095,228			45,961,417	93,432,554		139,393,971	6
					484,530	484,530	7
				65,529		65,529	8
53,187				3,241,702		3,241,702	9
31,002			1,319,534	1,235,009		2,554,543	10
					-65	-65	11
							12
				-276		-276	13
390				15,690		15,690	14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	INADVERTENT INTERCHANGE (NET)	OS	NA			
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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	12/31/2011	End of 2011/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)	
7,994							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
7,865,200			390,787,012	411,865,721	-52,705	802,600,028	

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	12/31/2011	2011/Q4

FOOTNOTE DATA

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

This company is a Qualifying Facility (QF)pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

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

Footnote Linked. See note on 326, Row: 1, col/item:

Schedule Page: 326 Line No.: 4 Column: l

OUT OF PERIOD ADJUSTMENT: AUBURNDALE POWER PARTNERS - ENERGY ($58,839) .

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Comission and therefore have no designated FERC Rate Schedule or Tariff Number.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Services Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326 Line No.: 8 Column: l

OUT OF PERIOD ADJUSTMENT: CITRUS WORLD - ENERGY $250.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff.

Schedule Page: 326 Line No.: 10 Column: l

OUT OF PERIOD ADJUSTMENT: LAKE COUNTY - ENERGY $3,840.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326 Line No.: 12 Column: l

OUT OF PERIOD ADJUSTMENT: LAKE COGEN LIMITED - ENERGY ($437,918).

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326 Line No.: 14 Column: l

OUT OF PERIOD ADJUSTMENT: DADE COUNTY - ENERGY ($144,335).

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 2 Column: l

OUT OF PERIOD ADJUSTMENT: ORANGE COGEN LIMITED - ENERGY $14,226.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 4 Column: l

OUT OF PERIOD ADJUSTMENT: ORLANDO COGEN LIMITED - ENERGY $9,176 AND CAPACITY ($589).

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 6 Column: l

OUT OF PERIOD ADJUSTMENT: PASCO COUNTY - ENERGY $17,643.

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) 12/31/2011	2011/Q4

FOOTNOTE DATA

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 8 Column: l

OUT OF PERIOD ADJUSTMENT: PCS PHOSPHATE - ENERGY $6,116.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 10 Column: l

OUT OF PERIOD ADJUSTMENT: PINELLAS COUNTY - ENERGY $18,173.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 12 Column: l

OUT OF PERIOD ADJUSTMENT: POLK POWER PARTNERS - ENERGY $14,629.

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

This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchases from QF's are set by the Florida Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.1 Line No.: 14 Column: l

OUT OF PERIOD ADJUSTMENT: RIDGE GENERATING STATION - ENERGY $36,322.

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

OUT-OF-PERIOD ADJUSTMENT - CITY OF CHATTAHOOCHEE - CAPACITY $9614.

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

Footnote Linked. See note on 326.2, Row: 3, col/item:

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

OUT-OF-PERIOD ADJUSTMENT - CALPINE ENERGY SERVICES LLC - ENERGY $12474.

Schedule Page: 326.2 Line No.: 8 Column: c

Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

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

Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

Schedule Page: 326.2 Line No.: 12 Column: c

Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

Schedule Page: 326.2 Line No.: 14 Column: l

OUT-OF-PERIOD ADJUSTMENT - FLORIDA POWER AND LIGHT COMPANY - ENERGY ($535).

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

Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

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

2011 NEW SMYRNA BEACH - CAPACITY SALES CREDIT ($134819).

Schedule Page: 326.3 Line No.: 12 Column: c

Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

Schedule Page: 326.4 Line No.: 1 Column: l

OUT-OF-PERIOD ADJUSTMENT - RELIANT ENERGY SERVICES INCORPORATED - ENERGY $29184.

Schedule Page: 326.4 Line No.: 5 Column: l

OUT-OF-PERIOD ADJUSTMENT - SHADY HILLS POWER COMPANY - ENERGY $68218.

Schedule Page: 326.4 Line No.: 7 Column: l

OUT-OF-PERIOD ADJUSTMENT - SOUTHERN COMPANY SERVICES - ENERGY $484530.

Schedule Page: 326.4 Line No.: 11 Column: l

OUT-OF-PERIOD ADJUSTMENT - TAMPA ELECTRIC COMPANY - ENERGY ($65).

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(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 Classification (d)
1	CIty of Alachua-Gainesville	Progress Energy Florida	City of Alachua	LFP
2	City of Bartow	Progress Energy FLorida	City of Bartow	FNO
3	Calpine Energy Services	Various	Various	NF
4	Cargill Power Markets, LLC.	Various	Various	NF
5	Central Power and Lime	Various	Various	NF
6	Cobb Electric Membership	Various	Various	NF
7	Conoco, Inc.	Various	Various	NF
8	Constellation Energy	Various	Various	NF
9	Eagle Energy Partners	Various	Various	NF
10	Florida Municipal Power Authority	Various	Various	NF
11	Florida Municipal Power Authority	Progress Energy Florida	Florida Municipal Pwr Authority	FNO
12	FMPA/City of Quincy	Progress Energy Florida	City of Quincy	FNO
13	Florida Power & Light Co.	Various	Various	NF
14	Fortis Energy Marketing Trading	Various	Various	NF
15	Gainesville Regional Utilities	Progress Energy Florida	Gainesville Regional	LFP
16	Georgia Power Company	Progress Energy FLorida	Georgia Power Co.	OLF
17	City of Homestead	Progress Energy Florida	City of Homestead	LFP
18	City of Homestead	Progress Energy Florida	City of Homestead	NF
19	City of Homestead	Progress Energy Florida	City of Homestead	SFP
20	Kissimmee Utility Auth	Progress Energy Florida	Kissimmee Utility Auth	LFP
21	Lakeland Utilites	Various	Various	NF
22	City of Mt. Dora	Progress Energy Florida	City of Mt. Dora	FNO
23	JP Morgan Ventures	Various	Various	NF
24	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilites Comm of New Smyrna Beach	LFP
25	Utilities Comm of New Smyrna Beach	Progress Energy Florida	Utilities comm of New Smyrna Beah	LFP
26	Utilities Comm of New Smyrna Beach	Various`	Various	NF
27	Oglethorpe Power Corp	Various	Various	NF
28	Orange Cogen LP	Orange Cogen LP	Tampa Electric Company	LFP
29	Orlando Utilities Commission	Progress Energy Florida	Orlando Utilities Commission	LFP
30	Orlando Utilities Commission	Various	Various	NF
31	Rainbow Energy Marketing Corp.	Various	Various	NF
32	Reedy Creek Improvement Dist.	Various	Various	NF
33	Reedy Creek Improvement Dist.	Progress Energy Florida	Reedy Creek Improvement Dist	FNO
34	Reliant Energy Services	Reliant Energy Svcs	Florida Power & Light	LFP
	TOTAL			

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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.
T6/72	Crystal River Sub	Gainesville Regional	1		5,760	1
T6/136	Various	City of Bartow		603	603	2
T6/106	Various	Various		140	137	3
T6/230C	Various	Various		1,078	1,067	4
T6/141	Various	Various				5
T6/114	Various	Various				6
T6/232C	Various	Various				7
T6/63C	Various	Various				8
T6/257C	Various	Various				9
T6/31	Various	Various		1,754	1,719	10
T6/148	Various	Fla Mun Pwr Auth		4,151	4,151	11
T6/137	Various	City of Quincy		172	172	12
T6/7C	Various	Various		799	785	13
T6/285C	Various	Various				14
T6/73	Crystal River Sub	Gainesville Regional	12	109,767	104,007	15
FERC No. 105	Intercession City Sb	Ga Power Company	146			16
T6/130	Various	FL Power & Light	35	224,904	220,755	17
T6/52	Various	FL Power & Light		89	89	18
T6/53	Various	FL Power & Light				19
T6/74	Crystal River Sub	Kissimmee Utility	6	47,987	47,987	20
T6/56	Various	Various		901	885	21
T6/133	Various	City of Mt. Dora		209	209	22
T6/132	Various	Various		20	19	23
T6/75	Crystal River Sub	New Smyrna Beach	5	39,646	39,646	24
T6/138	Smyrna Sub	New Smyrna Beach	25	63,400	62,244	25
T6/12	Various	Various		268	267	26
T6/187C	Various	Various				27
T6/77	Orange Sub	Tampa Electric Co	23	76,430	76,430	28
T6/76	Crystal River Sub	Orlando Utilities Cm	14	114,908	114,908	29
T6/10	Various	Various		443	435	30
T6/35C	Various	Various		565	554	31
T6/14	Various	Various		321	315	32
T6/147	Various	Reedy Creek Imp		1,860	1,860	33
T6/92	Hudson Sub	FL Power & Light				34
			512	**1,378,296**	**1,350,770**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(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 Classification (d)
1	Reliant Energy Services	Various	Various	NF
2	Seminole Electric Coop	Progress Energy Florida	Seminole Electric Coop	SFP
3	Seminole Electric Coop	Various	Various	NF
4	Seminole Electric Coop	Progress Energy Florida	Seminole electric Coop	FNO
5	Southern Company of Florida	Various	Various	NF
6	City of Tallahassee	Progress Energy Floirda	City of Tallahassee	LFP
7	City of Tallahassee	City of Tallahassee	City of Tallahassee	LFP
8	City of Tallahassee	Various	Various	NF
9	Tampa Electric Company	Progress Enegy Florida	Tampa Electric Company	LFP
10	Tampa Electric Company	Various	Various	NF
11	Tampa Electric Company	Tampa Electric Company	Cities of Ft. Meade & Wachula	FNO
12	Tampa Electric Company	Progress Energy Floirda	Tampa Electric Company	SFP
13	Tennessee Valley Authoritty	Various	Various	NF
14	The Energy Authority	Progress Energy Florida	Gainesville Regional Utililites	LFP
15	The Energy Authority	Progress Energy Florida	Gainesville Regional Utilities	LFP
16	The Energy Authority	Various	Various	SFP
17	The Energy Authority	Various	Various	NF
18	City of Wauchula	Progress Energy Florida	City of Wachula	FNO
19	City of Williston	Progress Energy Florida	City of Williston	FNO
20	City of Winter Park	Progress Energy Florida	City of Winter Park	FNO
21	FPC Power Marketing	Various	Various	NF
22	Florida Municipal Power Auth-OS	Various	Various	OS
23	Reedy Creek-OS	Various	Various	OS
24	Seminole Electric Cooperative Inc.	Various	Various	OS
25	Southeastern Power Admin-OS	Various	Various	OS
26	Constellation Power Source	Various	Various	NF
27	Alabama Electric Coop	Various	Various	OS
28	City of New Symrna	Various	Various	NF
29	Pa-NJ-Maryland Int (PJM)	Various	Various	NF
30	Tennessee Valley Authority	Various	Various	NF
31	Carolina Power & Light	Various	Various	NF
32	Duke Power	Various	Various	NF
33				
34				
	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	12/31/2011	End of 2011/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.
T6/3	Various	Various				1
T6/24	Progress Energy FL	Seminole Elec Coop	11			2
T6/23	Various	Various		2,454	2,403	3
T6/143	Progress Energy FL	Various		23,931	23,931	4
T6/29C	Various	Various				5
T6/96	Progress Energy FL	City of Tallahassee	11	98,831	97,006	6
T6/97	Jackson Bluff Sub	City of Tallahassee	11	5,679	5,554	7
T6/19	Various	Various		255	250	8
T6/134	Progress Energy FL	Tampa Electric Co.	158	90,965	89,300	9
T6/160C	Various	Various		16,713	16,414	10
T6/98	Tampa Electric Co	Wachula				11
T6/25	Progress Energy FL	Tampa Electric Co.				12
T6/21C	Various	Various				13
T6/140	Progress Energy FL	Gainesville Regional	4	23,835	23,395	14
T6/139	Progress Energy FL	Gainesville Regionas	50	129,227	126,859	15
T6/62	Various	Various		24	24	16
T6/68C	Various	Various		64,472	63,360	17
T6/150	Various	City of Wauchula		26	26	18
T6/125	Various	City of Winter Park		73	73	19
T6/124	Various	City of Winter Park		944	944	20
T6/76C	Various	Various		18,395	18,043	21
T6/31	Various	Various				22
T6	Various	Various				23
T6	Various	Various				24
T6	Various	Various		212,057	198,184	25
T8	Various	Various				26
T6	Various	Various				27
T6	Various	Various				28
T6	Various	Various				29
T6/70	Various	Various				30
T8/76	Various	Various				31
T6	Various	Various				32
						33
						34
			512	**1,378,296**	**1,350,770**	

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.
15,329			15,329	1
1,153,044			1,153,044	2
470			470	3
4,072			4,072	4
				5
				6
				7
				8
623			623	9
6,448			6,448	10
7,985,226			7,985,226	11
376,045			376,045	12
-871			-871	13
				14
277,237			277,237	15
1,082,419			1,082,419	16
859,957			859,957	17
381			381	18
				19
132,994			132,994	20
4,999			4,999	21
472,811			472,811	22
117			117	23
111,768			111,768	24
613,518			613,518	25
1,591			1,591	26
84			84	27
554,185			554,185	28
319,599			319,599	29
-2,648			-2,648	30
2,770			2,770	31
-9,733			-9,733	32
4,405,100			4,405,100	33
				34
75,216,465	**0**	**0**	**75,216,465**	

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	12/31/2011	End of 2011/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.
				1
309,867			309,867	2
18,638			18,638	3
47,791,202			47,791,202	4
				5
278,731			278,731	6
266,344			266,344	7
3,408			3,408	8
4,043,438			4,043,438	9
94,670			94,670	10
219,001			219,001	11
				12
				13
171,512			171,512	14
1,272,567			1,272,567	15
91			91	16
275,078			275,078	17
28,722			28,722	18
168,917			168,917	19
2,032,882			2,032,882	20
-513,332			-513,332	21
23,400			23,400	22
-46,373			-46,373	23
75,854			75,854	24
329,527			329,527	25
				26
				27
				28
4,780			4,780	29
				30
6			6	31
				32
				33
				34
75,216,465	**0**	**0**	**75,216,465**	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
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28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	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	12/31/2011	End of 2011/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								
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	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	12/31/2011	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	5,247,910
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	250,927
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Environmental Reserve	641,685
7	Stores Burden Adjustment	-147,396
8	Stock Listing/Debt Rating Fees	470,492
9	Trustee Fees	391,596
10	Franchise Audit Fees	232,612
11	Accounting Adjustments	-1,918,090
12		
13		
14		
15		
16		
17		
18		
19		
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21		
22		
23		
24		
25		
26		
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44		
45		
46	TOTAL	5,169,736

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	12/31/2011	End of 2011/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			4,519,490		4,519,490
2	Steam Production Plant	72,717,643	316,929			73,034,572
3	Nuclear Production Plant	18,369,301	-764,852			17,604,449
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	74,388,157				74,388,157
7	Transmission Plant	41,846,319				41,846,319
8	Distribution Plant	115,187,520				115,187,520
9	Regional Transmission and Market Operation					
10	General Plant	14,040,011	42,658			14,082,669
11	Common Plant-Electric					
12	TOTAL	336,548,951	-405,265	4,519,490		340,663,176

B. Basis for Amortization Charges

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	12/31/2011	End of 2011/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	STEAM PRODUCTION						
13	311-Structures & Imprv						
14	Anclote Steam	37,686,948	80.00	-3.00	1.89	L2	16.70
15	Crystal River 1 & 2 St	75,347,013	80.00	-3.00	2.17	L2	10.50
16	Crystal River 4 & 5 St	149,641,354	80.00	-3.00	1.49	L2	33.00
17	Suwannee River Steam	5,100,438	80.00	-3.00	2.30	L2	3.50
18	Bartow/Anclote Pipelin	1,111,324	80.00	-3.00	1.82	L2	16.40
19	Transmission Substn-FL	15,484	80.00	-3.00	1.41	L2	73.00
20	312-Boiler Plant Equip						
21	Anclote Steam	105,906,279	48.00	-4.00	2.17	S0	16.50
22	Crystal River 1 & 2 St	191,806,828	48.00	-4.00	3.70	S0	10.40
23	Crystal River 4 & 5 St	470,641,903	48.00	-4.00	2.47	S0	33.00
24	Suwannee River Steam	14,934,174	48.00	-4.00	3.10	S0	3.50
25	Bartow/Anclote Pipelin	17,010,912	48.00	-4.00	2.56	S0	16.40
26	Railroad Cars	32,774,301	48.00	-4.00	3.35	S0	33.00
27	312.9-Boiler Pl Eq Coa						
28	Crystal River 1 & 2 St	1,023,482	48.00	-4.00	3.70	S0	
29	Crystal River 4 & 5 St	1,727,433	48.00	-4.00	2.47	S0	
30	314-Turbogenerator Unt						
31	Anclote Steam	110,175,409	55.00	-4.00	2.80	L0.5	16.10
32	Crystal River 1 & 2 St	124,977,426	55.00	-1.00	2.54	L0.5	10.20
33	Crystal River 4 & 5 St	192,644,939	55.00	-1.00	0.97	L0.5	31.00
34	Suwannee River Steam	12,035,553	55.00	-4.00	2.90	L0.5	3.50
35	315-Accessory Elec Equ						
36	Anclote Steam	26,465,047	65.00	-1.00	1.58	L0.5	16.70
37	Crystal River 1 & 2 St	35,779,320	65.00	-3.00	2.56	L0.5	10.50
38	Crystal River 4 & 5 St	80,573,182	65.00	-3.00	0.95	L0.5	33.00
39	Suwannee River Steam	2,719,876	65.00	-1.00	2.60	L0.5	3.50
40	Bartow/Anclote Pipelin	1,252,617	65.00	-4.00	1.36	L0.5	16.40
41	316-Misc Pwr Plnt Equi						
42	Anclote Steam	6,231,226	36.00	-3.00	1.65	S.5	15.40
43	Crystal River 1 & 2 St	6,216,718	36.00	-3.00	2.05	S.5	9.90
44	Crystal River 4 & 5 St	11,795,822	36.00	-4.00	2.12	S.5	28.00
45	Suwannee River Steam	508,755	36.00	-3.00	2.94	S.5	3.40
46	Bartow/Anclote Pipelin	152,597	36.00	-3.00	3.36	S.5	15.10
47	System - Steam	221,096	36.00	-4.40	2.90	S.5	33.90
48	Transmission Substn-FL	42,666	36.00	-4.40	2.90	S.5	32.50
49	NUCLEAR PRODUCTION						
50	321-Structures & Imprv						

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Crystal River #3	221,086,447	75.00	-3.00	1.46	L1.5	26.00
13	Tallahassee	4,590,511	75.00	-3.00	1.46	L1.5	26.00
14	322-Reactor Plnt Equip						
15	Crystal River #3	266,915,793	40.00	-4.00	3.30	R0.5	24.00
16	Tallahassee	2,006,295	40.00	-4.00	3.30	R0.5	24.00
17	323-Turbogenerator Unt						
18	Crystal River #3	92,342,668	30.00	-4.00	1.20	L0	23.00
19	Tallahassee	1,545,523	30.00	-4.00	1.20	L0	23.00
20	324-Accessory Elec Equ						
21	Crystal River #3	179,495,507	60.00	-1.00	1.42	R1.5	26.00
22	Tallahassee	645,490	60.00	-1.00	1.42	R1.5	26.00
23	325-Misc Pwr Plnt Equi						
24	Crystal River #3	34,204,339	25.00	-3.00	1.67	L1.5	22.00
25	Tallahassee	237,806	25.00	-3.00	1.67	L1.5	22.00
26	OTHER PRODUCTION						
27	341-Structures & Imprv						
28	Avon Park Peaking	405,755	55.00		0.64	L2	6.50
29	Bartow Peaking	1,074,388	55.00		1.69	L2	17.40
30	Bayboro Peaking	1,650,590	55.00		1.02	L2	19.40
31	Debary Peaking	4,966,043	55.00		2.70	L2	10.50
32	Debary Peaking P7-1New	4,714,633	55.00		3.30	L2	13.50
33	Higgins Peaking	791,388	55.00		2.90	L2	6.50
34	Hines Energy Complex	43,694,771	55.00		2.90	L2	23.00
35	Hines Energy Unit #2	44,311,953	55.00		2.90	L2	27.00
36	Hines Energy Unit #3	10,134,658	55.00		2.90	L2	24.00
37	Hines Energy Unit #4	23,595,878	55.00		2.90	L2	31.00
38	Intercession City #11	1,244,317	55.00		4.00	L2	12.50
39	Intercession City P1-6	3,728,718	55.00		2.90	L2	10.50
40	Intercession P12-P14	1,426,366	55.00		2.80	L2	26.00
41	Intercession P7-P10	9,423,437	55.00		2.54	L2	21.00
42	Rio Pinar Peaking	117,906	55.00		3.21	L2	6.50
43	Suwannee River Peaking	1,471,200	55.00		1.29	L2	14.40
44	Tiger Bay Cogen	10,620,577	55.00		1.70	L2	28.00
45	Turner Peaking	1,394,020	55.00		1.97	L2	6.50
46	University of Fla Coge	6,499,783	55.00		1.76	L2	23.00
47	342-Fuel Holders, Prod						
48	Avon Park Peaking	626,518	30.00	-1.00	4.80	R0.5	6.40
49	Bartow Peaking	1,749,941	30.00	-1.00	3.00	R0.5	16.80
50	Bartow Combined Cycle	640,823	30.00	-1.00	3.16	R0.5	32.00

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	12/31/2011	End of 2011/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	Bayboro Peaking	1,433,229	30.00	-1.00	2.99	R0.5	18.60
13	Debary Peaking	6,489,210	30.00	-1.00	2.60	R0.5	10.30
14	Debary Peaking P7-1New	7,947,534	30.00	-1.00	4.00	R0.5	13.10
15	Higgins Peaking	1,542,983	30.00	-1.00	5.40	R0.5	6.40
16	Hines Energy Complex	16,613,121	30.00	-1.00	3.20	R0.5	22.00
17	Hines Energy Unit #2	12,957,182	30.00	-1.00	3.20	R0.5	26.00
18	Hines Energy Unit #3	15,011,098	30.00	-1.00	3.20	R0.5	23.00
19	Hines Energy Unit #4	13,026,776	30.00	-1.00	3.20	R0.5	29.00
20	Intercession City #11	1,379,318	30.00	-1.00	4.40	R0.5	12.10
21	Intercession City P1-6	3,341,131	30.00	-1.00	6.60	R0.5	10.30
22	Intercession P12-P14	5,838,131	30.00	-1.00	3.00	R0.5	25.00
23	Intercession P7-P10	7,506,654	30.00	-1.00	2.83	R0.5	20.00
24	Rio Pinar Peaking	341,789	30.00	-1.00	4.00	R0.5	6.40
25	Suwannee River Peaking	3,753,285	30.00	-1.00	3.30	R0.5	14.00
26	Tiger Bay Cogen	3,053,255	30.00	-1.00	1.84	R0.5	27.00
27	Turner Peaking	2,593,574	30.00	-1.00	3.00	R0.5	6.40
28	University of Fla Coge	5,804,722	30.00	-1.00	2.05	R0.5	22.00
29	343-Prime Movers						
30	Avon Park Peaking	5,901,920	25.00		3.00	O1	6.40
31	Bartow Peaking	14,123,299	25.00		1.56	O1	16.40
32	Bartow Combined Cycle	631,951,442	25.00		3.33	O1	30.00
33	Bayboro Peaking	16,243,648	25.00		2.31	O1	18.10
34	Debary Peaking	26,938,792	25.00		3.00	O1	10.10
35	Debary Peaking P7-1New	63,579,691	25.00		3.70	O1	12.80
36	Higgins Peaking	9,787,748	25.00		2.90	O1	6.40
37	Hines Energy Complex	162,212,288	25.00		3.21	O1	21.00
38	Hines Energy Unit #2	122,363,181	25.00		3.30	O1	25.00
39	Hines Energy Unit #3	154,567,419	25.00		3.30	O1	22.00
40	Hines Energy Unit #4	197,127,254	25.00		3.28	O1	28.00
41	Intercession City #11	14,182,088	25.00		4.62	O1	11.90
42	Intercession City P1-6	23,371,270	25.00		2.70	O1	10.10
43	Intercession P12-P14	60,867,887	25.00		2.94	O1	24.00
44	Intercession P7-P10	61,658,589	25.00		2.58	O1	19.80
45	Rio Pinar Peaking	2,142,489	25.00		2.34	O1	6.40
46	Suwannee River Peaking	18,529,757	25.00		1.33	O1	13.70
47	Tiger Bay Cogen	37,360,343	25.00		1.39	O1	26.00
48	Turner Peaking	11,883,912	25.00		1.22	O1	6.40
49	University of Fla Coge	19,072,165	25.00		2.54	O1	22.00
50	344-Generators						

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	Avon Park Peaking	1,633,594	55.00		0.05	R1.5	6.40
13	Bartow Peaking	7,725,049	55.00		2.10	R1.5	16.90
14	Bayboro Peaking	3,283,046	55.00		1.41	R1.5	18.70
15	Debary Peaking	9,457,806	55.00		2.40	R1.5	10.30
16	Debary Peaking P7-1New	18,413,683	55.00		3.30	R1.5	13.10
17	Higgins Peaking	2,638,129	55.00		2.50	R1.5	6.40
18	Hines Energy Complex	44,807,805	55.00		2.90	R1.5	23.00
19	Hines Energy Unit #2	39,325,539	55.00		2.90	R1.5	27.00
20	Hines Energy Unit #3	50,311,679	55.00		2.90	R1.5	24.00
21	Hines Energy Unit #4	2,948,628	55.00		2.90	R1.5	31.00
22	Intercession City #11	2,664,079	55.00		4.00	R1.5	12.20
23	Intercession City P1-6	4,716,975	55.00		2.60	R1.5	10.30
24	Intercession P12-P14	16,681,378	55.00		2.51	R1.5	25.00
25	Intercession P7-P10	17,702,413	55.00		2.54	R1.5	21.00
26	Rio Pinar Peaking	430,677	55.00		2.30	R1.5	6.40
27	Suwannee River Peaking	5,021,099	55.00		1.40	R1.5	14.10
28	Tiger Bay Cogen	23,323,806	55.00		1.78	R1.5	27.00
29	Turner Peaking	4,611,530	55.00		2.40	R1.5	6.40
30	University of Fla Coge	3,561,068	55.00		1.83	R1.5	22.00
31	345-Accessory Elec Equ						
32	Avon Park Peaking	1,152,348	50.00	-1.00	0.46	S0.5	6.40
33	Bartow Peaking	2,133,581	50.00	-1.00	1.79	S0.5	16.90
34	Bayboro Peaking	1,134,520	50.00	-1.00	1.84	S0.5	18.70
35	Debary Peaking	5,814,579	50.00	-1.00	2.50	S0.5	10.30
36	Debary Peaking P7-1New	5,110,760	50.00	-1.00	3.40	S0.5	13.10
37	Higgins Peaking	2,559,304	50.00	-1.00	3.30	S0.5	6.40
38	Hines Energy Complex	21,946,282	50.00	-1.00	3.20	S0.5	22.00
39	Hines Energy Unit #2	17,793,092	50.00	-1.00	3.20	S0.5	26.00
40	Hines Energy Unit #3	21,394,234	50.00	-1.00	3.20	S0.5	23.00
41	Hines Energy Unit #4	25,663,669	50.00	-1.00	3.20	S0.5	29.00
42	Intercession City #11	3,630,191	50.00	-1.00	4.00	S0.5	12.20
43	Intercession City P1-6	3,292,138	50.00	-1.00	3.10	S0.5	10.30
44	Intercession P12-P14	6,911,508	50.00	-1.00	2.61	S0.5	25.00
45	Intercession P7-P10	5,257,047	50.00	-1.00	2.54	S0.5	21.00
46	Rio Pinar Peaking	502,947	50.00	-1.00	4.20	S0.5	6.40
47	Suwannee River Peaking	1,959,200	50.00	-1.00	1.84	S0.5	14.10
48	Tiger Bay Cogen	5,402,435	50.00	-1.00	2.07	S0.5	27.00
49	Turner Peaking	2,352,572	50.00	-1.00	3.00	S0.5	6.40
50	University of Fla Coge	5,569,377	50.00	-1.00	1.89	S0.5	22.00

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	12/31/2011	End of 2011/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	346-Misc Pwr Plnt Equi						
13	Avon Peaking	71,944	45.00	-1.00	3.20	R1.5	6.50
14	Bartow Peaking	144,659	45.00	-1.00	0.42	R1.5	17.20
15	Bayboro Peaking	401,960	45.00	-1.00	1.13	R1.5	19.20
16	Debary Peaking	633,498	45.00	-1.00	3.30	R1.5	10.40
17	Debary Peaking P7-1New	834,978	45.00	-1.00	4.20	R1.5	13.40
18	Higgins Peaking	116,970	45.00	-1.00	4.60	R1.5	6.50
19	Hines Energy Complex	3,722,885	45.00	-1.00	3.10	R1.5	23.00
20	Hines Energy Unit #2	2,670,859	45.00	-1.00	3.10	R1.5	27.00
21	Hines Energy Unit #3	1,579,733	45.00	-1.00	3.10	R1.5	24.00
22	Hines Energy Unit #4	3,283,683	45.00	-1.00	3.10	R1.5	31.00
23	Intercession City #11	188,206	45.00	-1.00	3.79	R1.5	12.40
24	Intercession City P1-6	851,960	45.00	-1.00	5.51	R1.5	10.40
25	Intercession P12-P14		45.00	-1.00	3.10	R1.5	33.00
26	Intercession P7-P10	1,075,045	45.00	-1.00	2.27	R1.5	21.00
27	Rio Pinar Peaking	23,650	45.00	-1.00	8.60	R1.5	6.50
28	Suwannee River Peaking	131,399	45.00	-1.00	3.20	R1.5	14.30
29	Tiger Bay Cogen	1,615,284	45.00	-1.00	1.40	R1.5	28.00
30	Turner Peaking	248,424	45.00	-1.00	2.08	R1.5	6.50
31	University of Fla Coge	995,623	45.00	-1.00	1.52	R1.5	23.00
32	System - Other	369,977	45.00	-1.00	1.51	R1.5	28.00
33	Transmission Substn-FL	26,668	45.00	-3.50	2.65	R1.5	
34	TRANSMISSION PLANT						
35	350-Land Rights	47,109,609	75.00		1.22	R3	53.00
36	352-Structures & Imprv	22,183,418	75.00	-15.00	1.44	R2.5	57.00
37	353-Station Equipment	464,755,285	53.00		1.81	R0.5	43.00
38	353-Station Equip-StnC	35,495,750	17.00		1.14	R3	7.20
39	354-Towers & Fixtures	66,502,241	65.00	-25.00	1.32	R3	31.00
40	355-Poles & Fixtures	378,920,206	38.00	-25.00	3.26	R2	29.00
41	356-O/H Condutrs&Devic	258,766,718	55.00	-20.00	1.88	R1.5	43.00
42	357-Undergrnd Conduit	7,010,980	55.00		1.17	R3	16.90
43	358-U/G Condutrs&Devic	9,611,266	50.00		1.99	R3	47.00
44	359-Roads and Trails	3,133,902	75.00		0.93	R3	69.00
45	DISTRIBUTION PLANT						
46	360-Land Rights	889,259	75.00		1.38	R3	67.00
47	361-Structures & Imprv	24,083,491	75.00	-10.00	1.42	R2	64.00
48	362-Station Equipment	425,912,586	60.00	-10.00	1.80	R0.5	51.00
49	364-Poles, Towers & Fx	480,664,661	29.00	-35.00	4.20	R4	18.80
50	365-O/H Condutrs&Devic	536,730,035	36.00	-20.00	2.73	R0.5	27.00

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/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	366-Undergrnd Conduit	204,650,089	67.00	-5.00	1.57	R2.5	56.00
13	367-U/G Condutrs&Devic	487,807,417	35.00	-5.00	2.95	R2	25.00
14	368-Line Transformers	477,057,510	27.00	-10.00	2.89	R2	21.00
15	369-Services-Overhead	76,327,425	34.00	-40.00	4.05	R3	15.40
16	369-Services-Undergrnd	388,282,584	43.00	-5.00	2.23	R0.5	35.00
17	370-Meters	117,505,352	18.00	-8.00	5.97	R0.5	13.50
18	371-Install on Cust Pr	2,383,459	25.00		3.63	R2	17.60
19	373-St Lighting & Sign	287,204,324	20.00	-5.00	3.07	L1.5	12.30
20	GENERAL PLANT						
21	390-Structures & Imprv	109,524,363	24.00	10.00	3.71	L0.5	17.80
22	391-Office Furn & Equp	12,002,325			14.30	7 yr amortization	
23	Transportation Equipmt						
24	392.1-Passenger Cars	1,048,380			8.70	N/A	
25	392.2-Light Trucks	20,729,139			8.70	N/A	
26	392.3-Heavy Trucks	18,108,315			4.80	N/A	
27	392.4-Special Trucks	99,060,485			5.00	N/A	
28	392.5-Trailers	8,690,361			1.70	N/A	
29	393-Stores Equipment	3,853,371			14.30	7 yr amortization	
30	394-Tools, Shop & Gara	14,436,955			14.30	7 yr amortization	
31	395-Laboratory Equipmt	2,925,359			14.30	7 yr amortization	
32	396-Power Operated Equ	4,149,498			5.80	N/A	
33	397-Communication Equp	64,846,598			14.30	7 yr amortization	
34	398-Misc Equipment	7,751,639			14.30	7 yr amortization	
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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) 12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: a

Bartow Steam Units 1, 2 and 3 were retired since the last filing of the rates. They were retired in June 2009.

Schedule Page: 336.1 Line No.: 50 Column: a

PEF utilized an estimated in service plant balance for calculation of the Bartow Combined Cycle. The plant went into service June 2009.

Schedule Page: 336.2 Line No.: 32 Column: a

PEF utilized an estimated in service plant balance for the calculation of the Bartow Combined Cycle. The plant went into service June 2009.

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	12/31/2011	End of 2011/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	Federal Energy Regulatory Commission Fee for				
2	Fiscal Year 2011	345,175		345,175	
3					
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45					
46	TOTAL	345,175		345,175	

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	12/31/2011	End of 2011/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.
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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	12/31/2011	End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. Electric, R, D & D Performed Externally:	
2	(1) Electric Power Research Institute	2011 Nuclear Power Program
3		2011 Efficiency and Innovative Technology
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Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
	497,683	930	497,683		2
	1,046,566	930	1,046,566		3
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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	12/31/2011	End of 2011/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	82,145,508		
4	Transmission	10,292,767		
5	Regional Market			
6	Distribution	40,091,240		
7	Customer Accounts	18,048,172		
8	Customer Service and Informational	13,286,018		
9	Sales	1,082,007		
10	Administrative and General	62,809,103		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	227,754,815		
12	Maintenance			
13	Production	45,353,881		
14	Transmission	7,319,271		
15	Regional Market			
16	Distribution	22,339,982		
17	Administrative and General	10,836		
18	TOTAL Maintenance (Total of lines 13 thru 17)	75,023,970		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	127,499,389		
21	Transmission (Enter Total of lines 4 and 14)	17,612,038		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	62,431,222		
24	Customer Accounts (Transcribe from line 7)	18,048,172		
25	Customer Service and Informational (Transcribe from line 8)	13,286,018		
26	Sales (Transcribe from line 9)	1,082,007		
27	Administrative and General (Enter Total of lines 10 and 17)	62,819,939		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	302,778,785	5,877,138	308,655,923
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

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	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	302,778,785	5,877,138	308,655,923
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	90,135,773	10,398,517	100,534,290
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	90,135,773	10,398,517	100,534,290
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores	9,447,169	-9,447,169	
79	Clearing Accounts	6,828,486	-6,828,486	
80	Misc Deferred Debits	2,286,977		2,286,977
81	All Other Accounts	1,205,166		1,205,166
82				
83				
84				
85				
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88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	19,767,798	-16,275,655	3,492,143
96	TOTAL SALARIES AND WAGES	412,682,356		412,682,356

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	12/31/2011	End of 2011/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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46	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	12/31/2011	End of 2011/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	703,210	mwh	4,584	105,013		2,375,033
2	Reactive Supply and Voltage	703,210	mwh	95,911	99,480		3,001,071
3	Regulation and Frequency Response				37,172		1,646,974
4	Energy Imbalance				17,286		-1,989,979
5	Operating Reserve - Spinning				3,704		157,805
6	Operating Reserve - Supplement				3,704		153,276
7	Other						
8	Total (Lines 1 thru 7)	1,406,420		100,495	266,359		5,344,180

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/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 (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	12,690	13	800	8,855	3,429	370			36
2	February	9,944	14	800	6,737	2,801	370			36
3	March	7,831	27	1700	5,514	1,911	370			36
4	Total for Quarter 1	30,465			21,106	8,141	1,110			108
5	April	10,418	27	1700	7,398	2,614	370			36
6	May	10,809	24	1800	7,624	2,782	367			36
7	June	12,012	21	1700	8,402	3,061	367		146	36
8	Total for Quarter 2	33,239			23,424	8,457	1,104		146	108
9	July	11,579	30	1700	8,101	2,929	367		146	36
10	August	11,941	12	1600	8,367	3,025	367		146	36
11	September	10,699	12	1700	7,511	2,639	367		146	36
12	Total for Quarter 3	34,219			23,979	8,593	1,101		438	108
13	October	9,066	11	1700	6,506	2,157	367			36
14	November	7,829	16	1600	5,549	1,877	367			36
15	December	7,397	23	1900	4,922	2,072	367			36
16	Total for Quarter 4	24,292			16,977	6,106	1,101			108
17	Total Year to Date/Year	122,215			85,486	31,297	4,416		584	432

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	37,596,936
3	Steam	12,824,510			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	2,712,393
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	50,494
7	Other	21,823,824			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	602,624
9	Net Generation (Enter Total of lines 3 through 8)	34,648,334	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	161,604
10	Purchases	7,865,200	27	Total Energy Losses	1,417,009
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	42,541,060
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	1,378,296			
17	Delivered	1,350,770			
18	Net Transmission for Other (Line 16 minus line 17)	27,526			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	42,541,060			

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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 in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	3,302,640	7,034	9,588	13	800
30	February	2,759,063	5,390	7,397	14	800
31	March	2,994,333	6,876	6,135	17	1700
32	April	3,544,261	9,523	8,090	27	1700
33	May	3,885,775	1,954	8,446	24	1800
34	June	4,255,890	3,318	9,106	21	1700
35	July	4,399,991	4,597	8,746	30	1700
36	August	4,554,501	1,441	9,025	12	1600
37	September	3,993,140	1,152	8,036	12	1700
38	October	3,194,017	6,827	7,080	11	1700
39	November	2,790,121	870	5,856	16	1600
40	December	2,867,328	1,512	5,020	23	1900
41	TOTAL	42,541,060	50,494			

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Anclote* (b)			Plant Name: *Crystal River South* (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			1966		
4	Year Last Unit was Installed	1978			1969		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1112.40			964.35		
6	Net Peak Demand on Plant - MW (60 minutes)	1029			874		
7	Plant Hours Connected to Load	14972			12266		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1047			874		
10	When Limited by Condenser Water	1011			873		
11	Average Number of Employees	71			85		
12	Net Generation, Exclusive of Plant Use - KWh	1613800			2628529		
13	Cost of Plant: Land and Land Rights	1869309			4316903		
14	Structures and Improvements	38190515			76412776		
15	Equipment Costs	258800301			371292532		
16	Asset Retirement Costs	507681			4923474		
17	Total Cost	299367806			456945685		
18	Cost per KW of Installed Capacity (line 17/5) Including	269.1188			473.8380		
19	Production Expenses: Oper, Supv, & Engr	1308445			2647827		
20	Fuel	134952953			127561503		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	596349			7425675		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			262		
26	Misc Steam (or Nuclear) Power Expenses	4251304			2320527		
27	Rents	0			0		
28	Allowances	576151			2913672		
29	Maintenance Supervision and Engineering	473892			1342493		
30	Maintenance of Structures	840806			333530		
31	Maintenance of Boiler (or reactor) Plant	2832188			5285956		
32	Maintenance of Electric Plant	-649549			6348615		
33	Maintenance of Misc Steam (or Nuclear) Plant	3170849			6103706		
34	Total Production Expenses	148353388			162283766		
35	Expenses per Net KWh	91.9280			61.7394		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Oil	Gas		Oil	Coal	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	BBL	MCF		BBL	Tons	
38	Quantity (Units) of Fuel Burned	365172	18077468	0	16994	1148048	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	6302	1015	0	5823	24250	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	79.407	5.991	0.000	100.735	89.670	0.000
41	Average Cost of Fuel per Unit Burned	71.616	5.991	0.000	107.135	108.878	0.000
42	Average Cost of Fuel Burned per Million BTU	11.363	5.900	0.000	18.399	4.490	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.150	0.080	0.000	0.000	0.050	0.000
44	Average BTU per KWh Net Generation	12907.000	12788.000	0.000	0.000	10592.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Crystal River North* (d)			Plant Name: *Suwanee* (e)			Plant Name: *Crystal River* (f)			Line No.
Steam			Steam			Nuclear			1
Conventional			Conventional			Conventional			2
1982			1953			1977			3
1984			1956			1977			4
1478.52			147.00			890.46			5
1432			130			797			6
15067			13852			0			7
0			0			0			8
1442			131			805			9
1422			129			789			10
262			32			604			11
8180128			402053			0			12
0			22059			73547			13
293695573			5355108			276551531			14
2087673614			33290197			617138600			15
0			1726484			0			16
2381369187			40393848			893763678			17
1610.6439			274.7881			1003.7101			18
7863080			317525			5971012			19
298529654			35418695			1720055			20
0			0			0			21
17340814			837135			6765007			22
0			0			0			23
0			0			0			24
12335			-218			2634648			25
3764185			1209328			47304807			26
0			0			0			27
1359465			363867			0			28
3765731			56404			10088303			29
527883			12796			4070063			30
13428286			268268			4563067			31
2713624			22188			3155749			32
5770260			780114			6092914			33
355075317			39286102			92365625			34
43.4071			97.7137			0.0000			35
Oil	Coal		Oil	Gas		Oil	Nuclear		36
BBL	Tons		BBL	MCF		BBL	MMBTU		37
39851	3514904	0	19250	4955394	0	0	0	0	38
5820	22144	0	6481	1025	0	0	0	0	39
118.125	84.010	0.000	43.817	6.226	0.000	0.000	0.000	0.000	40
114.915	83.314	0.000	32.673	6.226	0.000	0.000	0.000	0.000	41
19.744	3.762	0.000	5.041	6.075	0.000	0.000	0.000	0.000	42
0.000	0.040	0.000	0.070	0.080	0.000	0.000	0.000	0.000	43
0.000	9515.000	0.000	13356.000	12934.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Bartow CC* (b)			Plant Name: *Hines Energy Complex* (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	2009			1999		
4	Year Last Unit was Installed	2009			2007		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	1253.00			2265.75		
6	Net Peak Demand on Plant - MW (60 minutes)	1184			2056		
7	Plant Hours Connected to Load	37600			28915		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	1235			2199		
10	When Limited by Condenser Water	1133			1912		
11	Average Number of Employees	155			64		
12	Net Generation, Exclusive of Plant Use - KWh	7335638			12234266		
13	Cost of Plant: Land and Land Rights	1805121			11012624		
14	Structures and Improvements	61849672			87392431		
15	Equipment Costs	582344382			1001875268		
16	Asset Retirement Costs	0			0		
17	Total Cost	645999175			1100280323		
18	Cost per KW of Installed Capacity (line 17/5) Including	515.5620			485.6142		
19	Production Expenses: Oper, Supv, & Engr	2488913			4985216		
20	Fuel	347618135			563403421		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	2771831			3888165		
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	2002785			2671976		
27	Rents	0			0		
28	Allowances	305668			301773		
29	Maintenance Supervision and Engineering	592902			43506		
30	Maintenance of Structures	79371			201774		
31	Maintenance of Boiler (or reactor) Plant	1042464			0		
32	Maintenance of Electric Plant	2388378			14442319		
33	Maintenance of Misc Steam (or Nuclear) Plant	2604559			8152719		
34	Total Production Expenses	361895006			598090869		
35	Expenses per Net KWh	49.3338			48.8865		
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	4618	53230293	0	0	86252988	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	5764	1010	0	0	1012	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	127.066	6.504	0.000	9.672	6.525	0.000
41	Average Cost of Fuel per Unit Burned	193.011	6.504	0.000	0.000	6.525	0.000
42	Average Cost of Fuel Burned per Million BTU	33.485	6.439	0.000	0.000	6.445	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.160	0.050	0.000	0.000	0.050	0.000
44	Average BTU per KWh Net Generation	4764.000	7336.000	0.000	0.000	7138.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Tiger Bay* (d)			Plant Name: *Avon Park* (e)			Plant Name: *Bartow* (f)			Line No.
		Gas Turbine			Gas Turbine			Gas Turbine	1
		Conventional			Conventional			Conventional	2
		1995			1968			1972	3
		1995			1968			1972	4
		278.10			67.58			222.80	5
		216			59			202	6
		6297			26			587	7
		0			0			0	8
		227			70			226	9
		205			48			177	10
		0			0			0	11
		1209049			524			22124	12
		0			60423			0	13
		10530071			459739			1103900	14
		65767174			9668946			27518665	15
		0			0			0	16
		76297245			10189108			28622565	17
		274.3518			150.7711			128.4675	18
		631535			72733			374361	19
		55090882			82344			2215089	20
		0			0			0	21
		690795			79829			10351	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		812727			70092			96772	26
		0			0			0	27
		80085			827			0	28
		7679			11487			0	29
		5881			101484			3720	30
		0			0			0	31
		552656			128198			86217	32
		797236			72746			174170	33
		58669476			619740			2960680	34
		48.5253			1182.7099			133.8221	35
Gas			Oil	Gas		Oil	Gas		36
MCF			BBL	MCF		BBL	MCF		37
9139065	0	0	195	8914	0	5662	522109	0	38
1015	0	0	5795	1015	0	5760	1019	0	39
6.027	0.000	0.000	109.706	6.080	0.000	106.818	5.774	0.000	40
6.027	0.000	0.000	100.061	6.080	0.000	107.283	3.079	0.000	41
5.935	0.000	0.000	17.267	5.992	0.000	18.624	3.022	0.000	42
0.050	0.000	0.000	0.340	0.120	0.000	0.270	0.080	0.000	43
7676.000	0.000	0.000	19402.000	19405.000	0.000	14249.000	26822.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Bayboro* (b)			Plant Name: *Debary* (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	1973			1975		
4	Year Last Unit was Installed	1973			1992		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	226.80			861.22		
6	Net Peak Demand on Plant - MW (60 minutes)	204			701		
7	Plant Hours Connected to Load	98			2748		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	233			763		
10	When Limited by Condenser Water	174			638		
11	Average Number of Employees	0			14		
12	Net Generation, Exclusive of Plant Use - KWh	3442			158051		
13	Cost of Plant: Land and Land Rights	1597635			2055281		
14	Structures and Improvements	1692332			9707949		
15	Equipment Costs	24186463			153248336		
16	Asset Retirement Costs	0			0		
17	Total Cost	27476430			165011566		
18	Cost per KW of Installed Capacity (line 17/5) Including	121.1483			191.6021		
19	Production Expenses: Oper, Supv, & Engr	247669			1162225		
20	Fuel	939767			15864810		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	127270			436010		
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	105643			510041		
27	Rents	0			0		
28	Allowances	0			53230		
29	Maintenance Supervision and Engineering	557			0		
30	Maintenance of Structures	11966			61327		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	159333			781485		
33	Maintenance of Misc Steam (or Nuclear) Plant	218374			786090		
34	Total Production Expenses	1810579			19655218		
35	Expenses per Net KWh	526.0253			124.3600		
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	8182	0	0	41142	1917571	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	711	0	0	5790	1017	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	112.513	0.000	0.000	128.053	6.098	0.000
41	Average Cost of Fuel per Unit Burned	113.357	0.000	0.000	100.478	6.098	0.000
42	Average Cost of Fuel Burned per Million BTU	159.390	0.000	0.000	17.352	5.996	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.270	0.000	0.000	0.240	0.080	0.000
44	Average BTU per KWh Net Generation	1691.000	0.000	0.000	13847.000	13847.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development, (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Higgins* (d)			Plant Name: *Intercession City* (e)			Plant Name: *Rio Pinar* (f)			Line No.
Gas Turbine			Gas Turbine			Gas Turbine			1
Conventional			Conventional			Conventional			2
1969			1974			1970			3
1971			2000			1970			4
153.43			1310.20			19.29			5
111			1085			14			6
79			8120			9			7
0			0			0			8
116			982			15			9
105			1188			12			10
0			19			0			11
1563			514398			102			12
184271			746305			0			13
754453			15920553			115080			14
18691815			248958140			3454390			15
0			0			0			16
19630539			265624998			3569470			17
127.9446			202.7362			185.0425			18
135433			1506390			13383			19
206622			47648327			38130			20
0			0			0			21
193716			910730			24386			22
0			0			0			23
0			0			0			24
0			0			0			25
102623			791692			9770			26
0			0			0			27
1435			109233			0			28
4882			102597			0			29
13427			65178			670			30
0			0			0			31
71032			2340840			6409			32
397081			2646612			10968			33
1126251			56121599			103716			34
720.5701			109.1015			1016.8235			35
Oil	Gas		Oil	Gas		Oil			36
BBL	MCF		BBL	MCF		BBL			37
402	26913	0	58484	6330457	0	317	0	0	38
5823	38	0	5789	1010	0	5830	0	0	39
107.511	6.109	0.000	126.071	6.572	0.000	108.055	0.000	0.000	40
98.717	6.109	0.000	102.287	6.572	0.000	107.372	0.000	0.000	41
16.952	161.970	0.000	17.669	6.504	0.000	18.418	0.000	0.000	42
0.320	0.110	0.000	0.230	0.090	0.000	0.330	0.000	0.000	43
18974.000	705.000	0.000	13092.000	13092.000	0.000	18118.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Suwannee* (b)			Plant Name: *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	1980			1970		
4	Year Last Unit was Installed	1980			1974		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	183.60			180.98		
6	Net Peak Demand on Plant - MW (60 minutes)	178			159		
7	Plant Hours Connected to Load	1076			514		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	200			181		
10	When Limited by Condenser Water	155			137		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	44939			24602		
13	Cost of Plant: Land and Land Rights	0			824781		
14	Structures and Improvements	1471200			1591738		
15	Equipment Costs	33227781			26483867		
16	Asset Retirement Costs	0			0		
17	Total Cost	34698981			28900386		
18	Cost per KW of Installed Capacity (line 17/5) Including	188.9923			159.6883		
19	Production Expenses: Oper, Supv, & Engr	173507			167815		
20	Fuel	4340156			6912133		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4901			93839		
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	93979			125594		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	14382			0		
30	Maintenance of Structures	0			22903		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	169349			126924		
33	Maintenance of Misc Steam (or Nuclear) Plant	107875			110601		
34	Total Production Expenses	4904149			7559809		
35	Expenses per Net KWh	109.1290			307.2843		
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	6883	590175	0	65397	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	5790	1023	0	5791	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	6.256	0.000	120.958	0.000	0.000
41	Average Cost of Fuel per Unit Burned	91.552	6.256	0.000	104.734	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	15.811	6.118	0.000	18.087	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.230	0.090	0.000	0.280	0.000	0.000
44	Average BTU per KWh Net Generation	14316.000	14316.000	0.000	15393.000	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	12/31/2011	End of 2011/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: *Univ. of Florida* (d)	Plant Name: *Bartow* (e)	Plant Name: (f)	Line No.
Gas Turbine	Steam		1
Conventional	Conventional		2
1994			3
1994			4
43.00	0.00	0.00	5
47	0	0	6
6145	0	0	7
0	0	0	8
47	0	0	9
46	0	0	10
11	0	0	11
275126	0	0	12
0	0	0	13
6553271	0	0	14
37152371	0	0	15
0	2610937	0	16
43705642	2610937	0	17
1016.4103	0	0	18
651678	62468	0	19
15058685	4092	0	20
0	0	0	21
920280	3860	0	22
0	0	0	23
0	0	0	24
0	0	0	25
82742	-193	0	26
0	0	0	27
42071	38062	0	28
105288	-66511	0	29
365575	8476	0	30
0	17449	0	31
393011	0	0	32
675385	217	0	33
18294715	67920	0	34
66.4958	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
Gas									36
MCF									37
2964554	0	0	0	0	0	0	0	0	38
1016	0	0	0	0	0	0	0	0	39
5.079	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
5.079	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
5.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.060	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
10945.000	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	12/31/2011	End of 2011/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
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	0			0		
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	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	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	12/31/2011	End of 2011/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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	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	12/31/2011	End of 2011/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
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	0			0		
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	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	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	12/31/2011	End of 2011/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: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
0.00			0.00			0.00			5
0			0			0			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
0			0			0			11
0			0			0			12
0			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
0			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	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	12/31/2011	End of 2011/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
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	0			0		
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	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	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	12/31/2011	End of 2011/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: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	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	12/31/2011	End of 2011/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
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	0			0		
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	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	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
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FOOTNOTE DATA

Schedule Page: 402   Line No.: -1   Column: c

Bartow Steam Units 1, 2, and 3 were retired from service in June, 2009. 2010 is the first year with no generating activity.

Schedule Page: 402   Line No.: -1   Column: d

The following Electric Generating Plants are operated as joint operating facilities:

- Crystal River Nuclear Facility
- Intercession City Gas Turbine Facility

Schedule Page: 402   Line No.: -1   Column: f

Crystal River plant contains a pressurized water reactor. The nuclear fuel assemblies in the reactor contains enriched uranium. The cost of power generated at the plant is accounted for in accordance with instructions as set forth in the FERC Classification of Accounts. The cost of nuclear fuel is amortized to fuel expense on a unit of production basis.

Schedule Page: 402   Line No.: 39   Column: b1

2011 Calculations as related to oil & coal fired plant statistics are reported MBTU/BBL oil and MBTU/Ton coal in order to accurately reflect the data requested in the items on pages 402/403a. Prior period reports reflected BTU/gal oil and BTU/lb coal, respectively.

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

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	12/31/2011	End of 2011/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

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PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
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			17
			18
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			22
			23
			24
			25
			26
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			30
			31
			32
			33
			34
			35
			36
			37
			38

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GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
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44						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						21
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						25
						26
						27
						28
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						32
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						43
						44
						45
						46

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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	BARTOW PLANT	NORTHEAST #6	230.00	230.00	XLPE	3.86		1
11								
12	230 KV LINES	OVERHEAD						
13	AVON PARK	FORT MEADE	230.00	230.00	ST	22.87		1
14					CP	2.14		
15					WH	19.86		
16					WP	0.94		
17					SP		1.22	
18	AVON PARK	FISHEATING CREEK	230.00	230.00	SP	9.02		1
19					CP	17.05		
20					WH	3.29		
21	ANCLOTE PLANT	LARGO	230.00	230.00	SH	15.29		1
22					SP	8.54		
23	ANCLOTE PLANT	EAST CLEARWATER	230.00	230.00	SH		15.30	1
24	ANCLOTE PLANT	SEVEN SPRINGS	230.00	230.00	SP	7.71		1
25	ALTAMONTE	WOODSMERE	230.00	230.00	WP	0.10		1
26					CP	0.11	0.56	
27					WH	10.99		
28					SP	0.82		
29	BARCOLA	CITY OF LAKELAND TIE	230.00	230.00	WH	18.68		1
30	BARCOLA	PEBBLEDALE	230.00	230.00	CP	3.86		1
31	BROOKRIDGE	BROOKRIDGE	230.00	230.00	WP	0.21		1
32	CRYSTAL RIVER	CURLEW	230.00	230.00	ST	78.02	78.14	1
33	CRYSTAL RIVER	CENTRAL FLORIDA	230.00	230.00	ST	53.41	39.59	1
34	CRYSTAL RIVER	FT. WHITE	230.00	230.00	WH	73.50		1
35	CENTRAL FLORIDA	SILVER SPRINGS	230.00	230.00	ST	29.01	5.15	2
36					TOTAL	4,386.18	711.94	100

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
2156 KCM ACSR	2,282,211	20,844,985	23,127,196					2
2335 KCM ACSR	12,767	12,481,767	12,494,534					3
2335 KCM ACSR								4
2335 KCM ACSR	9,840	8,806,860	8,816,700					5
								6
								7
2500 KCM CU		1,985,950	1,985,950					8
2500 KCM CU	258,670	2,114,191	2,372,861					9
5000 KCMIL CU	114,492	27,339,468	27,453,960					10
								11
								12
1081 KCM ACSR	85,476	9,827,861	9,913,337					13
954 KCM ACSR								14
954 KCM ACSR								15
954 KCM ACSR								16
954 KCM ACSR								17
1590 KCM ACSR	1,321,547	8,904,607	10,226,154					18
1590 KCM ACSR								19
1590 KCM ACSR								20
1590 KCM ACSR	517,825	5,973,884	6,491,709					21
1590 KCM ACSR								22
1590 KCM ACSR		723,499	723,499					23
2335 KCM ACAR	1,237,622	1,387,207	2,624,829					24
1590 KCM ACSR	43,803	1,938,745	1,982,548					25
1590 KCM ACSR								26
1590 KCM ACSR								27
1590 KCM ACSR								28
1590 KCM ACSR	133,007	4,876,779	5,009,786					29
1622 KCM		3,432,843	3,432,843					30
1590 KCM ACSR		110,272	110,272					31
1590 KCM ACSR	1,283,122	12,446,479	13,729,601					32
1590 KCM ACSR	775,227	7,184,564	7,959,791					33
954 KCM ACSR	219,431	8,674,192	8,893,623					34
1590 KCM ACSR	442,027	3,947,189	4,389,216					35
	108,412,958	1,127,026,177	1,235,439,135	742,221	11,104,292		11,846,513	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	CENTRAL FLORIDA	SORRENTO	230.00	230.00	CP	14.65		1
2					SP	14.82		
3	CENTRAL FLORIDA	WINDERMERE	230.00	230.00	ST	69.76	46.61	1
4	CRAWFORDVILLE	PERRY	230.00	230.00	ST	14.02	1.35	2
5					WH	40.35		
6	CRAWFORDVILLE	PORT ST. JOE	230.00	230.00	WH	58.85		1
7					SP	2.65		
8					SH	0.65		
9	CRYSTAL RIVER EAST	SEVEN SPRINGS	230.00	230.00	ST		2.90	1
10	DEBARY	ALTAMONTE	230.00	230.00	SP	3.40	8.66	1
11					WH	3.06		
12					ST	0.56	3.23	
13					CP	0.49	0.32	
14	DEBARY	DELAND WEST	230.00	230.00	WH	7.15		1
15					WP	1.94		
16					CP	1.13		
17	DEBARY	NORTH LONGWOOD	230.00	230.00	WH	1.32		1
18					CH		2.70	
19					ST	3.36		
20					CP	0.42		
21					SP	9.15		
22	DEARMAN	SILVER SPRINGS NORTH	230.00	230.00	CP	4.27		1
23					ST		1.21	
24	DEBARY	WINTER SPRINGS	230.00	230.00	WH	3.23		1
25					SP	16.78		
26					ST	0.58		
27	FORT WHITE	SILVER SPRINGS	230.00	230.00	ST	1.46		1
28					SL	4.99		
29					CH	64.80		
30					CP	3.21		
31	40TH ST	PASADENA FSP	230.00	230.00	CP	0.19		1
32					SP	4.02		
33	FORT MEADE	VANDOLAH	230.00	230.00	SP	1.20		1
34					WH	21.05		
35					CP	1.80		
36					TOTAL	4,386.18	711.94	100

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	12/31/2011	End of 2011/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1590 KCM ACSR	1,621,137	10,444,336	12,065,473					1
1590 KCM ACSR								2
1590 KCM ACSR	1,128,343	7,935,305	9,063,648					3
954 KCM ACSR	2,019,515	6,276,774	8,296,289					4
954 KCM ACSR								5
954 KCM ACSR	626,506	8,848,993	9,475,499					6
954 KCM ACSR								7
954 KCM ACSR								8
1590 KCM ACSR	66,391	139,498	205,889					9
1590 KCM ACSR	284,757	2,865,499	3,150,256					10
1590 KCM ACSR								11
1590 KCM ACSR								12
1590/1431 KCM								13
1590 KCM ACSR	575,819	3,036,648	3,612,467					14
1590 KCM ACSR								15
1590 KCM ACSR								16
954 KCM ACSR	233,626	3,157,665	3,391,291					17
954 KCM ACSR								18
1590 KCM ACSR								19
1431 KCM ACSR								20
1590 KCM ACSR								21
954 KCM ACSR	195,181	1,624,744	1,819,925					22
954 KCM ACSR								23
1590 KCM ACSR	1,073,673	10,811,176	11,884,849					24
1590 KCM ACSR								25
1590 KCM ACSR								26
795 KCM ACSR	449,980	4,440,400	4,890,380					27
795 KCM ACSR								28
795 KCM ACSR								29
954 KCM ACSR								30
1590 KCM ACSR	2,510	2,016,770	2,019,280					31
1590 KCM ACSR								32
954 KCM ACSR	63,923	4,767,865	4,831,788					33
954 KCM ACSR								34
954 KCM ACSR								35
	108,412,958	1,127,026,177	1,235,439,135	742,221	11,104,292		11,846,513	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	12/31/2011	End of 2011/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)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	FORT MEADE	WEST LAKE WALES	230.00	230.00	ST	3.07		1
2					WH	16.68		
3					SP	3.02		1
4	TIGER BAY	TECO	230.00	230.00	CP	0.10		1
5					ST	5.86		
6					WH	1.38		
7	HINES ENERGY	FORT MEADE	230.00	230.00	SP	6.41		1
8	HINES ENERGY	BARCOLA	230.00	230.00	SP	3.09		1
9	HINES ENERGY	BARCOLA (2ND CIRCUIT)	230.00	230.00	SP	3.09		1
10	HINES ENERGY	TIGER BAY	230.00	230.00	SP	0.60	3.51	
11	HINES PLANT	HINES	230.00	230.00	SP	1.64		
12	HINES	WEST LAKE WALES	230.00	230.00	SP	20.57		1
13	OLD SUB NORTH	NEW SUB NORTH	230.00	230.00	SP	0.22		1
14	INTERCESSION CITY	LAKE BRYAN 2ND CIRCUIT	230.00	230.00	SP	7.84		1
15	KATHLEEN	WEST LAKELAND	230.00	230.00	WH	14.50		1
16					CP	1.31		
17	KATHLEEN	ZEPHYRHILLS NORTH	230.00	230.00	WH	0.83		1
18					CP	8.70		
19					WP	1.35		
20	LARGO	PASADENA	230.00	230.00	ST		1.61	1
21					SP	13.13		
22	LAKE TARPON	CURLEW	230.00	230.00	ST	4.32		1
23	LAKE TARPON	HIGGINS	230.00	230.00	CP	2.57		1
24					SP	3.02		
25	LAKE TARPON	LARGO	230.00	230.00	SP	14.49		1
26					CP	2.90		
27	LAKE TARPON	SEVEN SPRINGS	230.00	230.00	ST	2.90		1
28	LAKE TARPON	TECO EXIST	230.00	230.00	ST	0.68		1
29					SP	0.81		
30	NORTHEAST	CURLEW	230.00	230.00	ST	16.95	12.78	1
31	NORTHEAST	40TH ST.	230.00	230.00	CP	0.16		1
32					SP	8.25		
33	NORTH LONGWOOD	PIEDMONT	230.00	230.00	SP	0.31	4.04	1
34					WH	6.16		
35	NORTH LONGWOOD	FP&L CO TIE	230.00	230.00	SP	4.04		1
36					TOTAL	4,386.18	711.94	100

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	12/31/2011	End of 2011/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.
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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.
1081 KCM ACAR	55,284	5,437,092	5,492,376					1
1081 KCM ACAR								2
1622 ACSS/TW								3
1590/1081 KCM	359,563	133,977	493,540					4
1081 KCM ACAR								5
1081/954 KCM								6
954 KCM ACSR		3,129,916	3,129,916					7
954 KCM ACSR		1,837,874	1,837,874					8
954 KCM ACSR		1,449,137	1,449,137					9
954 KCM ACSR		1,565,007	1,565,007					10
954 KCM ACSR		1,573,680	1,573,680					11
1622 ACSS/TW	10,406,543	35,815,449	46,221,992					12
2335 KCM ACAR		194,088	194,088					13
1622 ACSS TW		6,053,041	6,053,041					14
1590 KCM ACSR	507,363	3,874,988	4,382,351					15
1590 KCM ACSR								16
1590 KCM ACSR	275,097	3,459,471	3,734,568					17
1590 KCM ACSR								18
1590 KCM ACSR								19
1590 KCM ACSR	152,473	3,247,219	3,399,692					20
1590 KCM ACSR								21
1590 KCM ACSR		959,079	959,079					22
1590 KCM ACSR	15,699	1,499,798	1,515,497					23
1590 KCM ACSR								24
1590 KCM ACSR	412,563	8,623,404	9,035,967					25
1590 KCM ACSR								26
1590 KCM ACSR	189,338	754,590	943,928					27
1590 KCM ACSR		197,855	197,855					28
1590 KCM ACSR								29
1590 KCM ACSR	1,524,958	3,657,476	5,182,434					30
1590 KCA ACSR	288,076	8,240,422	8,528,498					31
1081 KCA ACAR								32
954 KCM ACSR	16,834	1,412,503	1,429,337					33
954 KCM ACSR								34
954 KCM ACSR	207,841	1,306,348	1,514,189					35
	108,412,958	1,127,026,177	1,235,439,135	742,221	11,104,292		11,846,513	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1					WH	2.77		
2	NORTH LONGWOOD	RIO PINAR	230.00	230.00	SP	0.58	3.94	1
3					CP	0.21		
4					AT	10.91		
5	NEWBERRY	WILCOX	230.00	230.00	SP	19.33		1
6	NORTHEAST	PINELLAS	230.00	230.00	CP	1.90		1
7	PIEDMONT	SORRENTO	230.00	230.00	SP	4.24		1
8					CP	6.45		
9					WH	4.79		
10	PIEDMONT	WOODSMERE	230.00	230.00	WH	6.72		1
11	PORT ST. JOE	GULF POWER	230.00	230.00	ST	33.99		1
12	RIO PINAR	OUC TIE	230.00	230.00	SP	0.52		1
13					AT	2.19		
14	SILVER SPRINGS	DELAND WEST	230.00	230.00	SL	39.93		1
15					SH	0.92		
16					SP	1.57		
17	SUWANNEE RIVER PLANT	FORT WHITE	230.00	230.00	ST	38.08		1
18	SKY LAKE	OUC TIE	230.00	230.00	CP	2.40		1
19					WP	2.22		
20	SUWANNEE	PERRY	230.00	230.00	ST	28.61		1
21	SUWANNEE PEAKERS	SUWANNEE	230.00	230.00	WH	0.63		1
22	SUWANNEE	GEORGIA GPC TIE	230.00	230.00	ST	18.36		1
23	TIGER BAY	FORT MEADE 2	230.00	230.00	SP	0.44	1.78	1
24	ULMERTON	LARGO	230.00	230.00	ST	5.05		1
25	VANDOLAH	SEMINOLE	230.00	230.00	SP	0.03		1
26	VANDOLAH	WHIDDEN	230.00	230.00	SP	14.40		1
27	WINDERMERE	INTERCESSION CITY	230.00	230.00	SP	15.07		1
28					CP	0.14		
29	WINDERMERE	WOODSMERE	230.00	230.00	WH	4.68		1
30					ST	1.82		
31	WEST LAKE WALES	INTERCESSION CITY	230.00	230.00	WH			1
32			230.00	230.00	SP	0.07		
33	WEST LAKE WALES	FP&L TIE	230.00	230.00	AT	58.48		1
34	WEST LAKE WALES	TECO TIE	230.00	230.00	AT	2.29		1
35	WINDERMERE	OUC TIE	230.00	230.00	WH	1.31		1
36					TOTAL	4,386.18	711.94	100

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TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 KCM ACSR								1
1590 KCM ACSR	420,736	1,891,929	2,312,665					2
954 KCM ACSR								3
954 KCM ACSR								4
1590 KCM ACSR	661,118	5,772,719	6,433,837					5
954 KCM ACSR		8,106	8,106					6
1590 KCM ACSR	574,273	5,208,464	5,782,737					7
1590 KCM ACSR								8
1590 KCM ACSR								9
954 KCM ACSR	15,605	808,046	823,651					10
795 KCM ACSR	71,747	2,691,152	2,762,899					11
954 KCM ACSR	100,034	2,111,864	2,211,898					12
954 KCM ACSR								13
1590 KCM ACSR	54,890	6,791,700	6,846,590					14
1590 KCM ACSR								15
1590 KCM ACSR								16
954 KCM ACSR	199,660	2,362,830	2,562,490					17
954 KCM ACSR	121,530	1,272,855	1,394,385					18
954 KCM ACSR								19
795 KCM ACSR	151,754	1,320,102	1,471,856					20
795 KCM ACSR		297,948	297,948					21
954 KCM ACSR	104,190	1,110,105	1,214,295					22
954 KCM ACSR		779,443	779,443					23
1590 KCM ACSR	601,048	835,445	1,436,493					24
954 ACSS TW		376,498	376,498					25
1622 ACSS TW	2,965,994	14,174,052	17,140,046					26
954 KCM ACSR	135,968	6,493,904	6,629,872					27
1622 ACSS/TW								28
1590 KCM ACSR	19,739	1,162,053	1,181,792					29
1590 KCM ACSR								30
954/1081 KCM								31
1622ACSS TW	364,444	2,959,204	3,323,648					32
954 KCM ACSR	595,327	5,500,565	6,095,892					33
954 KCM ACSR	17,342	339,005	356,347					34
954 KCM ACSR		513,323	513,323					35
	108,412,958	1,127,026,177	1,235,439,135	742,221	11,104,292		11,846,513	36

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	WOODSMERE	OUC TIE	230.00	230.00	ST		0.92	1
2								
3	OTHER TRANS. LINES	OVERHEAD 115 & 69				2,819.83	435.20	
4	OTHER TRANS. LINES	UNDERGROUND 115				50.36		
5								
6	Total Overhead Transmission	Line Expenses				4,313.88	670.72	80
7		(230, 115, 69 Kv)						
8	NEW LINES FOR 2008							
9	CENTRAL FLORIDA	BUSHNELL EAST	230.00	230.00	SP	8.28		1
10	LAKE BRYAN	WINDERMERE	230.00	230.00	SP	9.76		2
11	BARTOW PLANT (OH)	NORTHEAST (GENERATION	230.00	230.00	SP	1.53		1
12	NORTHEAST	NORTHEAST (SUB BUS)	230.00	230.00	SP	0.17		1
13								
14	NEW LINES FOR 2009							
15	BARTOW PLANT	NORTHEAST #7	230.00	230.00	XLPE	3.84		1
16	BARTOW PLANT	NORTHEAST #8	230.00	230.00	XLPE	3.92		1
17	DUNDEE	WEST LK WALES (DWL1)	230.00	230.00	SP	9.79		2
18	DUNDEE	WEST LK WALES (DWL2)	230.00	230.00	SP		0.63	1
19								
20								
21	BARTOW PLANT	NORTHEAST #9 DUCT BANK		230.00				
22								
23								
24								
25	NEW LINES FOR 2010							
26	INTERCESSION CITY	DUNDEE (ICD1)	230.00	230.00	SP	20.26		2
27	INTERCESSION CITY	DUNDEE 2ND CIR (ICD2)	230.00	230.00	SP	0.81	20.33	2
28	AVALON	GIFFORD	230.00	230.00	SP	7.20		2
29	STANTON PLANT (OUC)	BITHLO (SPBX)	230.00	230.00	SP	5.90		2
30	SANFORD (FP&L)	BITHLO (SBX)	230.00	230.00	CP	0.01		
31	HOLDER	HOLDER STRINGBUS	230.00	230.00	CP	0.07		1
32								
33	NEW LINE FOR 2011							
34	HINES	WEST LK WALES CIR #2	230.00	230.00	SP	0.76	20.26	1
35								
36					TOTAL	4,386.18	711.94	100

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	12/31/2011	End of 2011/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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 KCM ACSR		4,479	4,479					1
								2
	54,396,179	586,044,950	640,441,129					3
	88,132	12,222,588	12,310,720					4
				742,221	11,104,292		11,846,513	5
	93,149,770	966,842,758	1,059,992,528	742,221	11,104,292		11,846,513	6
								7
								8
1622 ACSS/TW	4,175,417	6,101,584	10,277,001					9
1622 ACSS/TW	1,360,155	8,703,668	10,063,823					10
1590 ACSR		2,376,418	2,376,418					11
1590 ACSR		490,157	490,157					12
								13
								14
5000 KCMIL CU	114,492	27,339,468	27,453,960					15
5000 KCMIL CU	114,492	27,339,468	27,453,960					16
2627 ACSS/TW	1,524,275	13,745,557	15,269,832					17
2627 ACSS/TW		2,203,108	2,203,108					18
								19
								20
	114,492	6,191,261	6,305,753					21
								22
								23
								24
								25
2627 ACSS/TW/HS	3,132,810	28,904,391	32,037,201					26
2627 ACSS/TW/HS		8,919,630	8,919,630					27
2627 ACSS/TW	1,361,548	11,180,272	12,541,820					28
1622 ACSS/TW	972,402	8,049,607	9,022,009					29
	1,782,471		1,782,471					30
2627 ACSS/TW		75,864	75,864					31
								32
								33
1622 ACCS/TW	610,634	8,562,966	9,173,600					34
								35
	108,412,958	1,127,026,177	1,235,439,135	742,221	11,104,292		11,846,513	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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 422.4 Line No.: 35 Column: f

Account 156- Other Materials and Supplies Material reclassed from account 155 during 2011.

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	ICD2 78A	ICD2 78B	0.81	SP	14.00	1	1
2	CP 283 1A	CP 283 1B	3.28	CP	8.00	2	2
3	HINES ENERGY	W LK WALES	21.02	SP	8.00	1	1
4	HINES ENERGY	HEFM 4 (ADDITION)	0.32	SP	8.00	1	1
5	HINES ENERGY	HEFM 4 (REMOVAL)	-0.36	SP	8.00	1	1
6	HINES ENERGY	HEFM 2 (ADDITION)	0.18	SP	8.00	1	1
7	HINES ENERGY	HEFM 2 (REMOVAL)	-0.22	SP	8.00	1	1
8	FWL 84	W LK WALES (ADDITION)	10.66	SP	9.00	1	1
9	FWL 84	W LK WALES (REMOVAL)	-10.66	SP	9.00	1	1
10	HP 107	HP 108 (ADDITION)	0.14	CP	4.00	1	1
11	HP 107	HP 108 (REMOVAL)	-0.04	WP	4.00	1	1
12	CLL 82	HOWEY SEC (ADDITION)	0.38	CP	8.00	1	1
13	CLL 82	HOWEY SEC (REMOVAL)	-0.15	WP	8.00	1	1
14	QX 175 SW	GP CO (ADDITION)	0.54	CP	4.00	1	1
15	QX 175 SW	GP CO (REMOVAL)	-0.52	SH	4.00	1	1
16	ATWATER	QX 140SW (ADDITION)	7.00	SP	8.00	2	3
17	ATWATER	QX 140SW (REMOVAL)	-7.07	WP	8.00	2	3
18	PSJA1 100SW	APALACH	16.38	CP	14.00	2	2
19	PSJA2 101	APALACH	16.16	CP	7.00	1	1
20	APALACH	INDIAN PASS	-25.11	WP	7.00	1	1
21	LURAVILLE	FP 366 TAP (ADDITION)	5.69	CP	8.00	1	2
22	LURAVILLE	FP 366 TAP (REMOVAL)	-5.58	WP	8.00	1	2
23	RIO PINAR	EAST ORANGE	2.83	CP	14.00	1	1
24	WR 432	RIO PINAR (ADDITION)	0.01	CP	1.00	1	1
25	WR 432	RIO PINAR (REMOVAL)	-0.08	WP	1.00	1	1
26	RIO PINAR	RX 1 2 (ADDITION)	0.06	CP	1.00	1	1
27	RIO PINAR	RX 1 2 (REMOVAL)	-0.06	WP	1.00	1	1
28	CLARCONA	CROWN PT	5.92	CP	14.00	2	2
29	ASC 75	ASC 96 (REMOVAL)	-0.97	WP	24.00	2	2
30	DLM 147	LK MARION (ADDITION)	0.07	CP	3.00	1	1
31	DLM 147	LK MARION (REMOVAL)	-0.09	CP	3.00	1	1
32	LK MARION	LMP 3 (ADDITION)	0.12	CP	4.00	1	1
33	LK MARION	LMP 3 (REMOVAL)	-0.09	CP	4.00	1	1
34	BARNUM CITY	NORTHRIDGE	3.79	CP	14.00	1	1
35	ICB 179	BARNUM CITY (ADDITION)	0.05	CP	14.00	1	1
36	ICB 179	BARNUM CITY (REMOVAL)	-0.07	CP	14.00	1	1
37	CC 149	CC 150	0.14	ST	4.00	2	4
38	BBW 95	BROOKSVILLE W	0.20	CP	4.00	1	1
39	BBW 95	BROOKSVILLE W	-0.23	WP	4.00	1	1
40	BROOKSVILLE W	BWB 2-1/2 (ADDITION)	0.15	CP	3.00	1	1
41	BROOKSVILLE W	BWB 2 (REMOVAL)	-0.09	SP	3.00	1	1
42	BROOKSVILLE W	BWR 2-1/2 (ADDITION)	0.31	CP	5.00	1	1
43	BROOKSVILLE W	BWR 2 (REMOVAL)	-0.25	WP	5.00	1	1
44	TOTAL		44.65		342.00	57	63

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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 No.
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)	
2627	ACSS/TW	VERTICAL	230		1,506,503	194,799		1,701,302	1
954	ACSR	VERTICAL	230	811,644	692,235	1,201,592	-10,290	2,695,181	2
1622	ACSS/TW	VERTICAL	230	610,634	5,228,638	3,334,328		9,173,600	3
954	ACSR	VERTICAL	230		81,130	30,101		111,231	4
954	ACSR	VERTICAL	230				-81,193	-81,193	5
954	ACSR	VERTICAL	230		180,408	33,713		214,121	6
954	ACSR	VERTICAL	230				-58,195	-58,195	7
1622	ACSS/TW	VERTICAL	230		1,078,180	296,213		1,374,393	8
1622	ACSS/TW	VERTICAL	230				-63,715	-63,715	9
1272	ACSS/TW	VERTICAL	69		144,395	60,936		205,331	10
1272	ACSS/TW	VERTICAL	69				-2,218	-2,218	11
795	AAC	VERTICAL	69	11,130	167,992	79,032		258,154	12
795	AAC	VERTICAL	69				-42,749	-42,749	13
1272	ACSR/TW	VERTICAL	115		417,181	155,386		572,567	14
795	ACSR/TW	VERTICAL	115				-186,871	-186,871	15
1272	ACSS/TW	VERTICAL	115		2,077,689	919,553		2,997,242	16
795	ACSR	VERTICAL	115				-423,109	-423,109	17
954	ACSS/TW	VERTICAL	69	867,775	6,523,541	4,480,286		11,871,602	18
954	ACSS/TW	VERTICAL	69	867,775	3,040,626	235,230		4,143,631	19
2/0	CU	VERTICAL	69				-325,784	-325,784	20
954	ACSS/TW	VERTICAL	69	126,580	623,825	1,293,559		2,043,964	21
2/0	CU	VERTICAL	69				-442,832	-442,832	22
1272	ACSS/TW	VERTICAL	69	1,808,946	2,088,219	1,067,663		4,964,828	23
1272	ACSS/TW	VERTICAL	69		29,302	34,631		63,933	24
795	ACSR	VERTICAL	69				-3,767	-3,767	25
795	ACSR	VERTICAL	69		94,742	86,701		181,443	26
795	ACSR	VERTICAL	69				-7,073	-7,073	27
1272	ACSS/TW	VERTICAL	69	2,524,540	6,030,364	1,265,049		9,819,953	28
795	AAC	VERTICAL	69				-16,343	-16,343	29
1272	ACSS/TW	VERTICAL	69		119,795	82,654		202,449	30
795	AAC	VERTICAL	69				-3,349	-3,349	31
1272	ACSS/TW	VERTICAL	69	8,404	164,686	113,728		286,818	32
795	AAC	VERTICAL	69				-22,145	-22,145	33
1272	ACSS/TW	VERTICAL	69	915,147	1,700,250	1,264,591		3,879,988	34
1272	ACSS/TW	VERTICAL	69		126,469	75,198		201,667	35
795	AAC	VERTICAL	69				-6,807	-6,807	36
1590	ACSR	VERTICAL	230	10,120		76,137		86,257	37
1272	ACSW/TW	VERTICAL	115		430,290	102,160		532,450	38
556	ACSR	VERTICAL	115				-28,753	-28,753	39
1272	ACSS/TW	VERTICAL	115		406,507	124,533		531,040	40
336	ACSR	VERTICAL	115				-11,904	-11,904	41
954	ACSR	VERTICAL	115		289,277	94,728		384,005	42
954	ACSR	VERTICAL	115				-20,955	-20,955	43
				8,562,695	33,964,354	17,289,632	-1,884,101	57,932,580	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	12/31/2011	End of 2011/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	BROOKSVILLE W	BWSX 3 (ADDITION)	0.16	CP	5.00	1	1
2	BROOKSVILLE W	BWSX 3 (REMOVAL)	-0.14	CP	5.00	1	1
3	BROOKSVILLE W	BWX 2 (ADDITION)	0.09	CP	2.00	1	1
4	BROOKSVILLE W	BWX 2 (REMOVAL)	-0.10	WP	2.00	1	1
5	TURNER PLANT	FP&L CO (ADDITION)	7.03	CP/ST	8.00	2	2
6	TURNER PLANT	FP&L CO (REMOVAL)	-6.96	ST/WH	8.00	1	1
7							
8							
9							
10							
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42							
43							
44	TOTAL		44.65		342.00	57	63

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	12/31/2011	End of 2011/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	ACSR	VERTICAL	115		309,011	101,604		410,615	1
795	ACSR	VERTICAL	115				-41,006	-41,006	2
954	ACSR	VERTICAL	115		166,698	78,690		245,388	3
954	ACSR	VERTICAL	115				-4,379	-4,379	4
556	ACSR	VERTICAL	115		246,401	406,837		653,238	5
556	ACSR	VERTICAL	115				-80,664	-80,664	6
									7
									8
									9
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									39
									40
									41
									42
									43
				8,562,695	33,964,354	17,289,632	-1,884,101	57,932,580	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	12/31/2011	End of 2011/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 - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
2	40TH STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	40TH STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
4	51ST STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
5	51ST STREET - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
6	ALDERMAN - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	ANCLOTE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
8	ANCLOTE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	21.00	
9	BAYBORO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.09	
10	BAYVIEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	BAYWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
12	BELLEAIR - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	BROOKER CREEK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	12.00
15	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
16	BROOKSVILLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	13.00
17	BROOKSVILLE ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	2.40	10.00
18	BROOKSVILLE ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	4.16	
19	BUSHNELL EAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	CAMPS SECTION 7 MINE-COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	4.00	
21	CENTER HILL - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
22	CENTRAL PLAZA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	CONSOLIDATED ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	66.00	0.44	
25	CROSS BAYOU - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
26	CROSSROADS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.09	
27	CURLEW - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	DENHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
30	DISSTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
31	DUNEDIN - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	14.00
33	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
34	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
35	EAST CLEARWATER - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	ELFERS -COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
37	FLORAL CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	FLORA-MAR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	FLORIDA ROCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	2.40	
40	FLORIDA ROCK - COASTL FLORIDA REGION	DIST- UNATTENDED	69.00	4.16	

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	12/31/2011	End of 2011/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)	
60	2					1
60	2					2
250	1					3
80	2					4
300	1					5
90	3					6
100	2					7
12	2					8
60	2					9
100	2					10
40	1					11
80	2					12
60	2					13
150	1					14
100	1					15
60	2					16
11	3	1				17
9	3	1				18
12	1					19
18	4	1				20
13	3	1				21
60	2					22
120	4					23
2	1	3				24
150	3					25
80	2					26
110	3					27
90	3					28
150	1					29
80	2					30
60	3					31
200	1					32
200	1					33
250	1					34
150	3					35
100	2					36
13	3	1				37
100	2					38
5	3	1				39
5	3	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	12/31/2011	End of 2011/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	G.E. PINELLAS - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
2	GATEWAY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	HAMMOCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
4	HAMMOCK - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	4.16	
5	HERNANDO AIRPORT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	12.47	
6	HIGHLANDS - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
7	HIGGINS PLANT - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	KENNETH CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
9	LAND-O-LAKES - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
11	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	13.00
12	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	5.00
13	LARGO - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
14	MAXIMO - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
15	NEW PORT RICHEY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
16	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	15.00
17	NORTHEAST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.09	
18	OAKHURST - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
20	PALM HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
21	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
22	PASADENA - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	PILSBURY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
24	PINELLAS WELL FIELD - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	4.00	
25	PORT RICHEY WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
26	SAFETY HARBOR - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.09	
27	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
28	SEMINOLE - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.09	
29	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
30	SEVEN SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
31	SIXTEENTH ST. - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
32	STARKEY ROAD - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	TANGERINE - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	8.00
34	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
35	TARPON SPRINGS - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	TAYLOR AVE. - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	TRI-CITY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	TRILBY - COASTAL FLORIDA REGION	DIST - UNATTENDED	67.00	13.09	
39	ULMERTON - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
40	ULMERTON - COASTAL FLORIDA 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	12/31/2011	End of 2011/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
90	3					2
20	1					3
19	2					4
30	1					5
80	2					6
170	2					7
60	2					8
30	1					9
200	1					10
200	1					11
200	1					12
100	2					13
150	3					14
60	2					15
600	2					16
100	2					17
90	3					18
250	1					19
60	2					20
250	1					21
80	2					22
100	2					23
5	3	1				24
90	3					25
80	2					26
250	1					27
100	2					28
90	3					29
750	3					30
80	2					31
80	2					32
30	1					33
150	1					34
100	2					35
80	2					36
60	2					37
9	3	1				38
450	2					39
100	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	12/31/2011	End of 2011/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	ULMERTON WEST - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	VINOY - COASTAL FLORIDA REGION	DIST - UNATTENDED	115.00	13.09	
3	WALSINGHAM - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	ZEPHYRHILLS - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
6	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
7	ZEPHYRHILLS NORTH - COASTAL FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
8					
9					
10	ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
11	APALACHICOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
12	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
13	ARCHER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.00	
14	BEACON HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
15	BEVILLES CORNER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	CARRABELLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
17	CARRABELLE BEACH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	12.00	
18	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	67.00	12.00
19	CRAWFORDVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	CROSS CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.09	
21	EAST POINT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	FOLEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
23	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
24	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	4.00
25	FORT WHITE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
26	G.E. ALACHUA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
27	GAINESVILLE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	25.00	
28	GEORGIA PACIFIC - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
30	HIGH SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	7.20	
31	HULL ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	INDIAN PASS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
34	JASPER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	JENNINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	LURAVILLE -NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	MADISON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
38	MONTICELLO - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
39	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
40	NEWBERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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.
80	2					1
100	2					2
100	2					3
80	2					4
250	1					5
60	2					6
300	1					7
						8
						9
13	3	1				10
13	3	1				11
150	1					12
18	6	2				13
60	2					14
20	1					15
14	3	1				16
10	3	1				17
100	1					18
14	3	1				19
10	3	1				20
10	3	1				21
40	2					22
100	1					23
75	1					24
5	3	1				25
20	1					26
30	1					27
10	3	1				28
9	1					29
10	1	1				30
19	2					31
10	3	1				32
60	1					33
13	3	1				34
5	3	1				35
9	3	1				36
40	2					37
40	2					38
100	1					39
11	3					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	O'BRIEN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.00	
3	OCCIDENTAL #1 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	7.20	
4	OCCIDENTAL #2 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	4.16	
5	OCCIDENTAL #3 - NORTHERN FLORIDA REGION	DIST - UNATTENDED	120.00	4.16	
6	OCCIDENTAL SWIFT CREEK#1-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	4.00	
7	OCCIDENTAL SWIFT CREEK #1 - NORTHERN FLORIDA	DIST - UNATTENDED	115.00	25.00	
8	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	25.00	
9	OCCIDENTAL SWIFT CREEK#2-NORTHERN FLORIDA	DIST - UNATTENDED	115.00	13.00	
10	OCHLOCKONEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
11	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
12	PERRY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	PERRY NORTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
14	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
15	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	PORT ST. JOE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	12.00
17	RIVER JUNCTION - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
18	SOPCHOPPY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	ST. GEORGE ISLAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	ST. MARKS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
21	SUTTERS CREEK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	SUWANNEE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
23	TRENTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	UNIVERSITY OF FLORIDA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	22.90	
25	UNIVERSITY OF FLORIDA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.70	
26	WAUKEENAH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
27	WHITE SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	WILLISTON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29					
30	ADAMS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
31	ALAFAYA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
33	ALTAMONTE SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	APOPKA SOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	BARBERVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	BAY RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	BELLEVIEW - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	BEVERLY HILLS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	CASSADAGA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
40	CASSELBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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.
5	3	1				1
50	1					2
50	1					3
40	2					4
13	1					5
40	2					6
25	1					7
25	1					8
30	1					9
28	4	1				10
250	2					11
40	2					12
20	1					13
100	1					14
20	1					15
100	1					16
21	3	1				17
9	1					18
20	1					19
13	3	1				20
21	2					21
20	1					22
12	3	1				23
90	3					24
60	1					25
9	1					26
21	4	1				27
21	2					28
						29
20	1					30
60	2					31
300	1					32
100	2					33
90	3					34
40	3					35
40	2					36
100	2					37
60	2					38
60	2					39
130	3					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	CIRCLE SQUARE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	CITRUS HILL - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
3	CLARCONA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	CLERMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	COLEMAN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	CRYSTAL RIVER NORTH -NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
7	CRYSTAL RIVER SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
8	DELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
9	PINE RIDGE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
10	DELAND EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
11	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
12	DELTONA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
13	DELTONA EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
14	DOUGLAS AVENUE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
15	DUNNELLON TOWN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	EAGLENEST - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
17	EATONVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18	ECON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
19	EUSTIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	EUSTIS SOUTH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
21	FERN PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	FLORIDA GAS TRANSMISSION - NORTHERN FLORIDA	DIST - UNATTENDED	230.00	13.00	
23	GROVELAND - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	
25	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	13.00
26	HOLDER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
27	HOMOSASSA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
28	HOWEY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	
30	INGLIS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
31	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
32	INVERNESS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	KELLER ROAD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	KELLY PARK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	LADY LAKE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	LAKE ALOMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	LAKE EMMA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
38	LAKE HELEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	LAKE WEIR - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
40	LEBANON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	

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
50	2					2
90	3					3
60	2					4
29	2					5
19	3	1				6
9	3	1				7
100	2					8
30	1					9
90	3					10
75	1					11
130	3					12
90	3					13
60	2					14
40	2					15
21	2					16
90	3					17
100	2					18
60	2					19
63	2					20
30	1					21
50	1					22
40	2					23
250	1					24
550	2					25
40	2					26
20	1					27
13	3	1				28
100	1					29
11	1					30
160	2					31
60	2					32
60	2					33
11	1					34
40	2					35
50	2					36
100	2					37
55	2					38
21	2					39
10	3	1				40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	LIBSON - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	LOCKHART - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
3	LOCKWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	MAITLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	MARICAMP - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
7	MARTIN - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
8	MCINTOSH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	MINNEOLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	MONTVERDE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
11	MOUNT DORA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
12	MYRTLE LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
13	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
14	NORTH LONGWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
15	OCALA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	OCOEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
17	OKAHUMPKA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18	ORANGE BLOSSOM - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	115.00	14.00
20	ORANGE CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
21	OVIEDO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
23	PIEDMONT - NORTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
24	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
25	PLYMOUTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	14.00	
26	RAINBOW SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
27	REDDICK - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
28	ROSS PRAIRIE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	SANTOS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
30	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
31	SILVER SPRINGS - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	SILVER SPRINGS SHORES - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	SPRING LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	SPRING LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
35	TROPIC TERRACE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
36	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	69.00	7.00
37	TURNER PLANT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
38	TWIN COUNTY RANCH - NORTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	13.00	
39	UNIV OF CENTRAL FL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
40	UNIV OF CNTL FL NORTH - SOUTHERN 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	12/31/2011	End of 2011/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
100	2					2
30	1					3
40	2					4
90	3					5
40	2					6
20	1					7
11	1					8
20	1					9
100	2					10
40	2					11
100	2					12
250	1					13
100	2					14
33	1					15
90	3					16
40	2					17
60	2					18
224	1					19
60	2					20
90	3					21
250	1					22
100	2					23
13	3	1				24
9	1					25
21	2					26
29	2					27
30	1					28
22	1					29
250	1					30
20	1					31
40	2					32
90	3					33
300	1					34
40	2					35
160	2					36
40	2					37
40	2					38
60	2					39
60	2					40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	UMATILLA - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	WEIRSDALE - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
3	WEKIVA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
4	WELCH ROAD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
5	WEST CHAPMAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	WILDWOOD CITY - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
7	WINTER GARDEN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
8	WINTER GARDEN CITRUS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	12.47	
9	WINTER GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	13.00	0.24	
10	WINTER GARDEN CITRUS#2 - SOUTHERN FLORIDA	DIST - UNATTENDED	13.00	0.48	
11	WINTER PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
12	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
13	WINTER PARK EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
14	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	13.00
15	WINTER SPRINGS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
17	WOODSMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18	ZELLWOOD - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	ZUBER - NORTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20					
21	AGRICOLA #4 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	ARBUCKLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
23	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	AVON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
25	AVON PARK NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
26	BABSON PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
27	BARNUM CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
28	BAY HILL - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	BITHLO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
30	BITHLO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
31	BOGGY MARSH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	BONNET CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	CABBAGE ISLAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	CANOE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	4.00
35	CELEBRATION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
36	CENTRAL PARK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	CHAMPIONS GATE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	CITRUSVILLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
39	COLONIAL - SOUTHERN FLORIDA REGION	DIST-UNATTENDED	69.00	13.00	
40	CONWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	

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Florida Power Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2011	End of 2011/Q4

SUBSTATIONS (Continued)

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40	2					1
21	2					2
100	2					3
100	2					4
60	2					5
25	1					6
100	2					7
9	3					8
3	6					9
2	6					10
60	2					11
500	2					12
100	2					13
250	1					14
90	3					15
250	1					16
40	2					17
40	2					18
29	2					19
						20
9	1					21
9	1					22
120	3					23
450	2					24
40	2					25
20	1					26
60	2					27
90	3					28
50	2					29
30	1					30
100	2					31
60	2					32
60	2					33
30	1					34
60	2					35
90	3					36
70	2					37
20	1					38
30	1					39
40	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COUNTRY OAKS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
2	CROOKED LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
3	CROWN POINT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
4	CURRY FORD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
5	CYPRESSWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	DACO - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	25.00	
7	DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
8	DESOTO CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
9	DINNER LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
10	DUNDEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
11	DUNDEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
12	EAST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
13	EAST ORANGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
14	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	8.00
15	FISHEATING CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
17	FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18	FOUR CORNERS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	FROSTPROOF - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	HAINES CITY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
21	HEMPLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	HOLOPAW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	25.00	
23	HORSE CREEK #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	4.00	
24	HUNTERS CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
25	INTERNATIONAL DRIVE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	13.00	
26	ISLEWORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
27	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
28	LAKE BRYAN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	LAKE LUNTZ - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
30	LAKE MARION - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
31	LAKE OF THE HILLS - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	LAKE PLACID - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	LAKE PLACID NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	LAKE WILSON - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	LAKEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	LEISURE LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	LITTLE PAYNE CREEK#1-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	25.00	
39	LITTLE PAYNE CREEK#2-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	25.00	
40	MAGNOLIA RANCH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	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	12/31/2011	End of 2011/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
10	1					2
30	1					3
50	1					4
40	2					5
13	1					6
20	1					7
21	2					8
67	2					9
20	1					10
250	1					11
40	2					12
120	3					13
150	1					14
11	1					15
200	1					16
10	1					17
90	3					18
50	2					19
80	2					20
110	3					21
25	6					22
9	1					23
110	3					24
100	2					25
60	2					26
500	2					27
90	3					28
100	2					29
40	2					30
20	1					31
40	2					32
20	2					33
60	2					34
40	2					35
55	2					36
11	1					37
13	1					38
13	1					39
60	2					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	MARLEY ROAD - SOUTHERN FLORIDA REGION	DIST- UNATTENDED	69.00	13.00	
2	MEADOW WOODS EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
3	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
4	MEADOWS WOODS SOUTH-SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
5	MIDWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6	MULBERRY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	4.00	
7	NARCOOSEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
8	NORALYN #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.00	
9	NORALYN #1 - SOUTHERN FLORIDA REGION	DIST- UNATTENDED	69.00	13.09	
10	NORALYN #1 - SOUTHERN FLORIDA REGION	DIST- UNATTENDED	69.00	4.16	
11	NORALYN #2 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	66.00	2.40	
12	ODESSA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
13	ORANGEWOOD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
14	PARKWAY - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
15	PEMBROKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
16	PINECASTLE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	13.09	
17	POINCIANA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
18	POINCIANA NORTH - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
19	REEDY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
20	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	14.00
21	RIO PINAR - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
22	SAND LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
23	SAND MOUNTAIN - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
24	SEBRING EAST - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
25	SHINGLE CREEK - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
26	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	13.00
27	SKY LAKE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
28	SOUTH BARTOW - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
29	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	25.00	
30	SOUTH FORT MEADE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	115.00	7.20	
31	SUNFLOWER - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
32	SUN'N LAKES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
33	TAFT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
34	TAUNTON RD - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
35	VINELAND - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
36	WAUCHULA - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
37	WEST DAVENPORT - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
38	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	13.00
39	WEST LAKE WALES - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
40	WESTRIDGE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	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	12/31/2011	End of 2011/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.
30	1					1
30	1					2
200	1					3
90	3					4
30	1					5
5	3	1				6
90	3					7
9	3	1				8
9	3					9
9	3					10
9	3	1				11
30	1					12
100	2					13
20	1					14
2	3	1				15
40	2					16
100	2					17
30	1					18
40	2					19
500	2					20
100	2					21
80	2					22
9	3	1				23
20	1					24
100	2					25
250	1					26
90	3					27
11	1					28
21	3					29
45	2					30
60	2					31
60	2					32
60	2					33
20	1					34
130	3					35
21	2					36
60	2					37
250	1					38
11	1					39
70	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	12/31/2011	End of 2011/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	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	13.00	4.00	
2	WEWAHOOTEE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.09	
3	WHIDDEN CREEK #1 - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	67.00	4.00	
4	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	230.00	69.00	
5	WINDERMERE - SOUTHERN FLORIDA REGION	DIST - UNATTENDED	69.00	13.00	
6					
7	TOTAL DISTRIBUTION		37602.00	8122.45	336.00
8					
9	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
10	BROOKRIDGE - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
11	BROOKSVILLE WEST - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
12	BROOKSVILLE WEST - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
13	HIGGINS PLANT - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
14	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
15	HUDSON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	7.20
16	LAKE TARPON - COASTAL FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
17	NEW RIVER - COASTAL FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
18					
19	BRONSON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
20	DRIFTON - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	5.00
21	GINNIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
22	GUMBAY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
23	HAVANA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
24	IDYLWILD - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	138.00	69.00	12.00
25	QUINCY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	4.00
26	SUWANNEE 230 KV - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	14.00
27	TALLAHASSEE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	8.00
28	WILCOX - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
29	LIBERTY - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	
30	ANDERSEN - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	14.00
31	BARBERVILLE - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	66.00	33.00
32	CAMP LAKE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	15.00
33	CAMP LAKE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
34	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
35	CENTRAL FLORIDA - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
36	CLERMONT EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	14.00
37	CRYSTAL RIVER EAST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	116.00	
38	DALLAS - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
39	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
40	DELAND WEST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	115.00	69.00	15.00

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.
9	3	1				1
13	3	1				2
20	1					3
250	1					4
40	2					5
						6
28541	710	46				7
						8
750	1					9
500	2					10
250	1					11
300	1					12
250	1					13
500	2					14
250	1					15
1500	2	1				16
250	1					17
						18
150	1					19
105	2					20
250	1					21
75	1					22
75	1					23
150	1					24
75	1					25
400	2					26
120	2					27
150	1					28
150	1					29
132	2					30
150	1					31
150	1					32
300	1					33
1500	2					34
450	2					35
250	1					36
250	1					37
250	1					38
200	1					39
125	1					40

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/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	HAINES CREEK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
2	MARTIN WEST - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
3	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
4	ROSS PRAIRIE - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
5	SORRENTO - NORTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
6					
7	AVALON - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
8	BARCOLA - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
9	GIFFORD - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
10	GRIFFIN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	13.00
11	HAINES CITY EAST - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
12	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
13	INTERCESSION CITY - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	13.00
14	KATHLEEN - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	512.00	230.00	14.00
15	NORTH BARTOW - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	
16	SOUTH POLK - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	115.00	
17	VANDOLAH - SOUTHERN FLORIDA REGION	TRANS - UNATTENDED	230.00	69.00	23.00
18					
19	TOTAL TRANSMISSION		10926.00	4345.00	260.20
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
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	12/31/2011	End of 2011/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
200	1					2
300	1					3
250	1					4
250	1					5
						6
250	1					7
150	1					8
300	1					9
250	1					10
300	1					11
250	1					12
250	1					13
750	1					14
150	1					15
300	2					16
400	2					17
						18
14607	58	1				19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Florida Power Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report 2011/Q4

FOOTNOTE DATA

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.: 17 Column: h

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

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	12/31/2011	End of 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Applications - Investment	PESC	various	2,825,704
3	Applications - Support	PESC	various	3,190,827
4	Audit Planning & Corporate Acitivties	PESC	various	467,037
5	Budget & Business Planning	PESC	various	345,374
6	Business Applications Services	PESC	various	4,803,622
7	Business Technology Support	PESC	various	2,136,812
8	Capital Markets	PESC	various	334,048
9	Commercial Transactions	PESC	various	400,682
10	Communications	PESC	various	2,136,351
11	Community Relations Support	PESC	various	296,192
12	Compensation Design & Evaluation	PESC	various	400,485
13	Contracts - Materials & Services	PESC	various	535,470
14	Corporate Ethics Program	PESC	various	298,588
15	Corporate Governance	PESC	various	1,850,306
16	Corporate Security Oversight	PESC	various	1,233,117
17	Corporate Strategy & Messaging	PESC	various	1,292,741
18	Deferred Compensation Plans	PESC	926	513,464
19	Depreciation Expense	PESC	923	6,987,511
20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer & Market Services	PEC	146	1,786,456
22	Power Operations Group	PEC	146	5,310,532
23	Nuclear Generation Group	PEC	146	1,691,795
24	Energy Delivery Services	PEC	146	2,010,841
25	Miscellaneous Materials	PEC	146	471,484
26	Power Operations Group	PESC	146	334,548
27	Transmission Operations & Planning	PESC	146	297,153
28	Corporate Relations & Admin Services	PESC	146	293,184
29	Revenue Sharing	PT Holding	146	1,764,860
30	Network Services	PT Holding	146	283,175
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Desktop Services	PESC	various	4,149,292

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Disbursements - Traditional	PESC	various	558,278
4	Energy Conservation Support	PESC	various	384,896
5	Energy Delivery Support	PESC	various	2,386,542
6	Energy Supply Support	PESC	various	2,184,221
7	Enterprise Risk Management	PESC	various	560,831
8	Environmental & Safety	PESC	various	583,835
9	Environmental Health & Safety Standards& Oversight	PESC	various	1,736,816
10	Executive Management & Support	PESC	various	31,061,511
11	External Reporting	PESC	various	2,547,936
12	Federal External Relations	PESC	various	806,081
13	Federal Regulatory Matters	PESC	various	470,503
14	Financial & Strategic Planning - Enterprise	PESC	various	518,236
15	Financial & Strategic Planning - Utilities	PESC	various	634,265
16	Flight Operations	PESC	various	3,662,367
17	HR Policy & Benefits Administration	PESC	various	473,413
18	Information Services	PESC	various	336,230
19	Insurance Management	PESC	various	367,669
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Internal Reporting & Cost Management	PESC	various	4,173,118
3	Investor Relations	PESC	various	488,733
4	IT&T Architecture	PESC	various	652,682

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	12/31/2011	End of 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5	IT&T Infrastructure	PESC	various	5,621,721
6	IT&T Infrastructure - Capital	PESC	various	908,526
7	IT&T Security	PESC	various	2,561,022
8	Labor & Employment Matters	PESC	various	309,246
9	Labor Accruals	PESC	920	360,564
10	Land Acquisition & Management	PESC	various	385,278
11	Leasehold Improvements	PESC	923	2,212,980
12	Liability & Workers Comp Insurance	PESC	925	2,299,034
13	Litigation Claims Settlements	PESC	925	706,859
14	Maintain Facilities - Corporate	PESC	various	1,602,506
15	Management Consultation & Employee Relations	PESC	various	2,281,194
16	Market Research	PESC	various	391,801
17	Misc Service Company Corporate Expenses	PESC	various	1,916,787
18	Month-End Close/Internal Controls	PESC	various	2,795,105
19	Multifunction Printing Devices/Copier/Fax	PESC	various	995,482
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	New Generation Planning Support	PESC	various	409,338
3	Nuclear Support	PESC	various	975,684
4	NuStart	PESC	421	352,607
5	Operating Lease	PESC	931	1,271,820
6	Other Insurance	PESC	925	1,936,898

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7	Payroll Processing	PESC	various	391,820
8	Perform Audits	PESC	various	1,373,495
9	Performance Share Sub-Plan	PESC	926	1,909,011
10	Procurement - Materials & Services	PESC	various	586,123
11	Property Taxes	PESC	923	621,457
12	Recruiting	PESC	various	598,492
13	Regulatory Reporting & Support	PESC	various	2,076,895
14	Rent & Lease Administration	PESC	various	1,929,003
15	Restricted Stock Units	PESC	926	3,833,294
16	SERP & Pension Restoration	PESC	926	2,733,955
17	Svc Company Tax Expense & Tax Savings Initative	PESC	923, 426.5	10,036,880
18	Service Company Infrastructure	PESC	various	6,045,574
19	State and Local External Relations	PESC	various	268,134
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	State Regulatory Reporting & Support	PESC	various	780,666
3	Supplier Diversity	PESC	various	260,212
4	Supply Chain Governance	PESC	various	1,188,523
5	Tax Compliance	PESC	various	640,256
6	Tax Planning	PESC	various	543,089
7	Utility Communications	PESC	various	665,587
8	Vehicle Claim Settlements	PESC	various	874,065

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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
9	Vendor & Commodity Management	PESC	various	303,706
10	Wireless Services	PESC	various	2,181,956
11	Wireline Infrastructure	PESC	various	3,498,050
12	Miscellaneous Materials	PESC	various	1,782,347
13	Customer & Market Services	PEC	various	1,177,841
14	Distribution Engineering & Operations	PEC	various	2,431,986
15	Efficiency and Innovative Technology	PEC	various	26,181,166
16	Energy Supply	PEC	920, 921	432,145
17	Fuels & Power Optimization	PEC	various	5,208,688
18	Nuclear Operations	PEC	various	8,229,379
19	Nuclear Engineering	PEC	various	4,139,314
20	**Non-power Goods or Services Provided for Affiliate**			
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Nuclear Oversight	PEC	various	931,863
3	Nuclear Generation	PEC	various	455,585
4	Nuclear Information Technology	PEC	528	627,578
5	Power Generation	PEC	various	5,526,507
6	Transmission & Operations Planning	PEC	various	1,510,008
7	Efficiency & Innovative Technology Support	PESC	various	-1,461,354
8	Sublease Revenue	PESC	454, 904	-250,636
9	Telecom Investments	PESC	various	-5,262,049
10	Maintain Facilities - Regional	PESC	various	250,692

Name of Respondent Florida Power Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2011	Year/Period of Report End of 2011/Q4

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Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
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20	**Non-power Goods or Services Provided for Affiliate**			
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Schedule Page: 429 Line No.: 2 Column: a

- Description: Projects to develop new applications or enhance business solutions to meet new or expanded business or regulatory requirements or to add functionality; includes O&M component of capitalized software projects.
- Methods of Allocation: Direct cost and Three Factor ratio.

Schedule Page: 429 Line No.: 2 Column: b

Progress Energy Service Company, LLC

Schedule Page: 429 Line No.: 2 Column: c

107, 182.3, 183, 186, 408.1, 417.1, 549, 566, 580, 588, 905, 908, 920, 921, 923, 926

Schedule Page: 429 Line No.: 3 Column: a

- Description: Support and maintain business applications
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 3 Column: c

408.1, 566, 580, 588, 905, 908, 920, 921, 923, 926

Schedule Page: 429 Line No.: 4 Column: a

- Description: Amortization of ASC 420 costs associated with exited facilities for which lease period remains; reserve based on present value of difference between future lease/rent payments and anticipated sub-lease revenue.
- Method of Allocation: Headcount ratio.

Schedule Page: 429 Line No.: 4 Column: c

408.1, 920, 921, 923, 926, 930.1, 930.2, 931

Schedule Page: 429 Line No.: 5 Column: a

- Description: Perform budgeting and business planning.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 5 Column: c

408.1, 524, 560, 920, 921, 923, 926

Schedule Page: 429 Line No.: 6 Column: a

- Description: Operate and maintain technology solutions to retain existing business functionality. Includes the cost of the data center and extended data center, storage, servers and mainframe costs.
- Methods of Allocation: Direct cost using IT Application Chargeback ratio and Three factor ratio.

Schedule Page: 429 Line No.: 6 Column: c

184, 408.1, 566, 588, 921, 923, 926

Schedule Page: 429 Line No.: 7 Column: a

- Description: Functional and end user support for Service Company technology, training and administrative costs.
- Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 7 Column: c

184, 408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429 Line No.: 8 Column: a

- Description: Long-term financing, revolving credit agreements, interest rate hedging, mortgage compliance, rating agencies, bank relations, planning.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 8 Column: c

408.1, 920, 921, 926, 930.2

Schedule Page: 429 Line No.: 9 Column: a

- Description: Commercial and real property transactions.

☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 9 Column: c

107, 408.1, 920, 921, 926

Schedule Page: 429 Line No.: 10 Column: a

☐ Description: Engineering and maintenance of voice/data/wireless infrastructure for SCADA, LAN/WAN, circuit outages and non-ED radios.
☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 10 Column: c

408.1, 529, 588, 920, 921, 923, 926, 935

Schedule Page: 429 Line No.: 11 Column: a

☐ Description: Administrative and regional support, consultation, event coordination, relationship management and sponsorship support.
☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 11 Column: c

408.1, 426.1, 920, 921, 923, 926

Schedule Page: 429 Line No.: 12 Column: a

☐ Description: Design, administration and compliance of base pay, merit, incentives; policies for employees.
☐ Method of Allocation: Headcount ratio.

Schedule Page: 429 Line No.: 12 Column: c

408.1, 920, 921, 926, 930.2

Schedule Page: 429 Line No.: 13 Column: a

☐ Description: Maintain contracts; lead and support category analysis; Contract reviews; fleet agreements; liaison with Legal Department, sourcing strategy development for PESC and Energy Delivery.
☐ Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 13 Column: c

163, 234, 408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429 Line No.: 14 Column: a

☐ Description: Corporate ethics programs including education and investigations.
☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 14 Column: c

408.1, 920, 921, 923, 926

Schedule Page: 429 Line No.: 15 Column: a

☐ Description: General corporate, Finance, intellectual property, patents, trademarks, SEC, tax and shareholder relations.
☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429 Line No.: 15 Column: c

186, 408.1, 920, 921, 923, 926, 930.1, 930.2, 931

Schedule Page: 429 Line No.: 16 Column: a

☐ Description: Corporate security activities and compliance excluding guard forces.
☐ Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 16 Column: c

408.1, 920, 921, 923, 926, 931, 935

Schedule Page: 429 Line No.: 17 Column: a

☐ Description: Brand design, consultation, management, and oversight.
☐ Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 17 Column: c

408.1, 426.1, 920, 921, 923, 926, 930.1, 930.2, 931, 935

Schedule Page: 429 Line No.: 18 Column: a

- Description: Costs for management of elected deferrals of PSSP awards as well as management compensation and incentives.
- Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 19 Column: a

- Description: Depreciation on Service Company assets; primarily consists of capitalized software, telecommunications infrastructure, IT equipment, furniture and fixtures.
- Method of Allocation: Three factor ratio.

Schedule Page: 429 Line No.: 21 Column: a

- Description: This includes goods or services such as Customer Service Management, Performance Solutions, and Utility Business Unit Demand driven support from the Service Company.
- Methods of Allocation: Direct Charge, Total Customers Ratio or Headcount Ratio.

Schedule Page: 429 Line No.: 21 Column: b

Carolina Power & Light d/b/a Progress Energy Carolinas, Inc.

Schedule Page: 429 Line No.: 22 Column: a

- Description: This includes goods or services such as Power Generation, Power Operations, Regulated Services, Regulated Fuels, Environmental Health & Safety, Power Generation Engineering, Power Generation Business Improvement for fossil, hydro and CT plants, and Utility Business Unit Demand Driven support from the Service Company.
- Methods of Allocation: Direct Charge or Maximum Dependable Capacity Ratio.

Schedule Page: 429 Line No.: 23 Column: a

- Description: This includes goods or services such as Management and Administrative costs of the Crystal River 3 Nuclear Plant, Nuclear Projects & Construction, Nuclear Engineering,and Nuclear Operations.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 24 Column: a

- Description: This includes goods or services such as Distribution Control Center, Asset Management, Data Integrity Group, Environmental, Metering, Performance Support, and Resource Management & Construction.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 25 Column: a

- Description: This includes charges for miscellaneous materials.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 26 Column: a

- Description: This includes goods or services such as Power Generation, Power Operations, Regulated Services, Regulated Fuels, Environmental Health & Safety, Power Generation Engineering, and Power Generation Business Improvement for fossil, hydro and CT plants. For 2011 these charges also include Merger and Integration costs.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 26 Column: b

Progress Energy Service Company, LLC

Schedule Page: 429 Line No.: 27 Column: a

- Description: This includes goods or services such as Transmission Asset Management, System Planning & Regulatory Performance, Transmission Construction & Engineering, and Transmission Area Maintenance. For 2011 thes charges also include Merger and Integration costs.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 28 Column: a

- Description: This includes goods or services such as Corporate Services, Real Estate, Warehouse Mgmt, Salvage & Freight, and Environmental Services. For 2011 these charges also include Merger and Integration costs.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 29 Column: a

- Description: This includes Revenue Sharing goods or services.
- Method of Allocation: Direct Charge only.

Schedule Page: 429 Line No.: 29 Column: b

PT Holding Company, LLC

Schedule Page: 429 Line No.: 30 Column: a

- Description: This includes Network goods or services.
- Method of Allocation: Direct Charge only.

Schedule Page: 429.1 Line No.: 2 Column: a

- Description: Provide desktop computing hardware, software, operating system and access to the Progress Energy network including underlying services and end-user support.
- Methods of Allocation: Direct cost using IT Device Rate and Three factor ratio.

Schedule Page: 429.1 Line No.: 2 Column: c

107, 184, 186, 566, 588, 908, 921

Schedule Page: 429.1 Line No.: 3 Column: a

- Description: Payment of vendors and related analysis and reporting; vendor file maintenance.
- Method of Allocation: Invoice ratio.

Schedule Page: 429.1 Line No.: 3 Column: c

408.1, 524, 920, 921, 923, 926, 930.2

Schedule Page: 429.1 Line No.: 4 Column: a

- Description: Service Company support of the Energy Conservation organization.

Method of Allocation: Direct cost only.

Schedule Page: 429.1 Line No.: 4 Column: c

107, 182.3, 583, 593, 908, 909

Schedule Page: 429.1 Line No.: 5 Column: a

- Description: Service Company support of the Energy Delivery organization.
- Method of Allocation: Direct cost only.

Schedule Page: 429.1 Line No.: 5 Column: c

107, 114, 163, 186, 408.1, 417.1, 547, 556, 560, 561.2, 561.5, 562, 563, 566, 568, 570, 571, 573, 580, 581, 582, 583, 584, 585, 586, 587, 588, 589, 590, 591, 592, 593, 594, 595, 596, 597, 598, 902, 903, 921, 926

Schedule Page: 429.1 Line No.: 6 Column: a

- Description: Service Company support of the Energy Supply organization.

Method of Allocation: Direct cost only.

Schedule Page: 429.1 Line No.: 6 Column: c

107, 151, 154, 163, 184, 186, 408.1, 500, 501, 502, 504, 505, 506, 510, 511, 512, 513, 514, 546, 547, 548, 549, 551, 552, 553, 554, 557, 926

Schedule Page: 429.1 Line No.: 7 Column: a

- Description: Research, compile and provide data and information; evaluate risks; make recommendations.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 7 Column: c

408.1, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 8 Column: a

- Description: Environmental and Occupational Safety & Health Administration (OSHA) matters.
- Method of Allocation: Direct cost only.

Schedule Page: 429.1 Line No.: 8 Column: c

107, 184, 228.4, 408.1, 502, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 9 Column: a

- Description: Governance of EH&S standards and policies.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 9 Column: c

408.1, 920, 921, 923, 926, 930.2, 931, 935

Schedule Page: 429.1 Line No.: 10 Column: a

- Description: Executive costs and projects such as: Coordinate BOD meeting agendas and presentations, monthly Chief Executive Officer (CEO) letter, annual CEO evaluation; Finance and Operations & Nuclear Oversight Committees; coordinate agenda, presentations, advance mailings, meeting minutes; various SMC needs including non-BOD presentations, speeches.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.1 Line No.: 10 Column: c

408.1, 426.1, 426.5, 920, 921, 923, 926, 930.1, 930.2, 931

Schedule Page: 429.1 Line No.: 11 Column: a

- Description: Reporting necessary to meet SEC requirements and to complete consolidation work, includes accounting policy and research and audit fees.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.1 Line No.: 11 Column: c

408.1, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 12 Column: a

- Description: Outreach to federal legislature and agencies, identify and evaluate potential policy changes, develop policy positions, build relationships, advocate positions, collaborate with like-minded companies and associations/coalitions, establish support and shape outcomes.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 12 Column: c

408.1, 426.4, 920, 921, 926

Schedule Page: 429.1 Line No.: 13 Column: a

- Description: Outreach to federal legislature and agencies, identify and evaluate potential policy changes, develop policy positions, build relationships, advocate positions, collaborate with like-minded companies and associations/coalitions, establish support and shape outcomes.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 13 Column: c

408.1, 920, 921, 923, 926

Schedule Page: 429.1 Line No.: 14 Column: a

- Description: Manage various strategic initiatives and projects sanctioned by senior management including analysis and interpretation of competitor strategies and financials as well as assessing regulatory, competitive, legal and market; manage consolidated financial forecast, earnings and cash flow projections; various analyses of O&M and other areas of significant financial impact; support Investor Relations and Treasury for analyst meetings, earnings releases, rating agencies and financings; scenario developments; BOD and SMC support; manage functional requirements of UI dynamics; facilitate and support overall strategic planning framework including development of corporate strategic plan and support of utility specific strategic and business planning processes.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 14 Column: c

408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.1 Line No.: 15 Column: a

- Description: Managing various utility strategic initiatives and projects sanctioned by senior management including analyzing/interpreting competitor strategies and financials as well as assessing regulatory, competitive, legal and market dynamics; facilitate and support overall strategic planning framework including development of utility strategic plans and support of associated processes.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.1 Line No.: 15 Column: c

107, 183, 408.1, 524, 556, 569.2, 580, 920, 921, 926

Schedule Page: 429.1 Line No.: 16 Column: a

- Description: Operations and maintenance of corporate aircraft.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.1 Line No.: 16 Column: c

408.1, 920, 921, 923, 926, 930.2, 931

Schedule Page: 429.1 Line No.: 17 Column: a

- Description: Employee information line, transition support administration, employee survey administration, new hire processing, absence management, relocation; vendor management, and compensation administration.
- Method of Allocation: Headcount ratio.

Schedule Page: 429.1 Line No.: 17 Column: c

408.1, 426.1, 920, 921, 923, 926, 935

Schedule Page: 429.1 Line No.: 18 Column: a

- Description: Corporate library, records, policies and procedures, copy services, real estate documents center.
- Method of Allocation: Headcount ratio.

Schedule Page: 429.1 Line No.: 18 Column: c

408.1, 920, 921, 923, 926, 935

Schedule Page: 429.1 Line No.: 19 Column: a

- Description: Identify insurable risks and manage insurance and self-insurance programs and related requirements, nuclear property, nuclear extra expense, nuclear liability primary, suppliers & transporters nuclear liability insurance, nuclear workers program, nuclear secondary financial protection, excess general liability, crime, excess workers' compensation (WC), non-nuclear property; primary WC & United States long shore & harbor workers insurance, primary general liability, pollution liability programs, state self-insurance renewals (NC, SC, FL, WC and auto).
- Method of Allocation: Three factor ratio.

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) 12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 429.1 Line No.: 19 Column: c

408.1, 920, 921, 923, 926

Schedule Page: 429.2 Line No.: 2 Column: a

- Description: Internal financial reporting to support legal entities and business units.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 2 Column: c

107, 184, 408.1, 524, 560, 580, 920, 921, 923, 926, 930.1, 930.2

Schedule Page: 429.2 Line No.: 3 Column: a

- Description: Manage relations with the financial community.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 3 Column: c

408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 4 Column: a

- Description: Architecture and life cycle planning for servers and peripheral, transport, data network, wireless, mobile, measuring and collaboration, desktops, laptops, ruggedized system, voice, video, etc.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 4 Column: c

408.1, 426.5, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 5 Column: a

- Description: Department administrative budget, department administrative support, account executives, directors, principals, videoconferencing support, education assistance, cash and non cash awards.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 5 Column: c

408.1, 426.1, 904, 920, 921, 923, 926, 930.1, 930.2, 931

Schedule Page: 429.2 Line No.: 6 Column: a

- Description: Projects to develop new services to meet business technical or regulatory requirements. Includes all technical support activities for hardware, software, data, voice, wireless, video communications and facilities infrastructure such as HVAC, Motor Generators, etc.
- Method of Allocation: Direct cost only.

Schedule Page: 429.2 Line No.: 6 Column: c

107, 186, 506

Schedule Page: 429.2 Line No.: 7 Column: a

- Description: Develop and monitor compliance with cyber security policy to ensure integrity of company data.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 7 Column: c

408.1, 920, 921, 923, 926, 930.2, 935

Schedule Page: 429.2 Line No.: 8 Column: a

- Description: Employment, labor relations, workers' compensation and benefit matters.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 8 Column: c

408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 9 Column: a

- Description: Monthly accrual for PESC labor costs resulting from timing of

payroll cycles.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 10 Column: a

- Description: Timber and lakeshore activities; land disposition.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 10 Column: c

408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 11 Column: a

- Description: Amortization of long-term improvements made to leased corporate facilities, including office construction and facility up fits (elevators, windows), primarily Progress Energy Building (PEB) and Two Progress Plaza (TPP).
- Method of Allocation: Three factor ratio.

Schedule Page: 429.2 Line No.: 12 Column: a

- Description: Excess workers compensation insurance.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 13 Column: a

- Description: Legal claim settlements associated with employment/labor and injury/damage related cases.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 14 Column: a

- Description: Maintenance of corporate buildings, including mail, cleaning, landscaping, utilities, repairs.
- Method of Allocation: Headcount ratio.

Schedule Page: 429.2 Line No.: 14 Column: c

408.1, 920, 921, 923, 926, 930.2, 935

Schedule Page: 429.2 Line No.: 15 Column: a

- Description: Labor relations strategy, negotiations, management consultation regarding memorandum of agreement (MOA); grievances and arbitrations; Equal Employment Opportunity (EEO) compliance, reporting and investigations; develop HR strategies to support company and business needs; use key metrics to proactively identify issues and recommend solutions before they impact the business; serve as liaison to/from HR to the business (implement standard operating procedures, policies); conflict resolution between management and employees.
- Methods of Allocation: Direct cost and Headcount ratio.

Schedule Page: 429.2 Line No.: 15 Column: c

408.1, 920, 921, 926, 930.2

Schedule Page: 429.2 Line No.: 16 Column: a

- Description: Provide customer-focused research and consulting services, including: develop, maintain and apply customer databases and tools; develop, manage, analyze and interpret customer satisfaction/feedback programs and provide customer service, delivery and demand side management (DSM) organizations prioritized guidance to improve and maintain customer satisfaction; develop, manage, analyze and interpret customer perceptions research to support key utility initiatives and to support CIG account management, DSM, Distribution, etc.; design, manage, analyze and interpret ad hoc research to help guide development and to evaluate the effectiveness of brand advertising and marketing/promotional communications, efficiency and demand response programs, and other optional products and services; design, administer and report internal studies to help guide business decisions and evaluate programs.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 16 Column: c

408.1, 920, 921, 923, 926, 931

Schedule Page: 429.2 Line No.: 17 Column: a

- Description: Includes true-ups for burden residuals, account reconciliation write-offs and other miscellaneous items not included in other categories.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 17 Column: c

419, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 18 Column: a

- Description: Activities necessary to perform monthly closing and controls such as accruals, journal entries, account reconciliations and analysis, evaluation of unusual transactions, control documentation.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.2 Line No.: 18 Column: c

107, 408.1, 524, 560, 580, 908, 920, 921, 923, 926, 930.2

Schedule Page: 429.2 Line No.: 19 Column: a

- Description: Provide hardware and software used to produce hard copy and sometimes soft copy output.
- Method of Allocation: Headcount ratio.

Schedule Page: 429.2 Line No.: 19 Column: c

408.1, 920, 921, 926, 935

Schedule Page: 429.3 Line No.: 2 Column: a

- Description: Service Company support of the New Generation Planning organization.

Method of Allocation: Direct cost only.

Schedule Page: 429.3 Line No.: 2 Column: c

107, 408.1, 583, 920, 921, 926

Schedule Page: 429.3 Line No.: 3 Column: a

- Description: Service Company support of the Nuclear organization.

Method of Allocation: Direct cost only.

Schedule Page: 429.3 Line No.: 3 Column: c

107, 121, 163, 183, 408.1, 519, 520, 523, 524, 528, 529, 530, 531, 532, 566, 920, 921, 926

Schedule Page: 429.3 Line No.: 4 Column: a

- Description: Earnings related to NuStart.
- Methods of Allocation: Direct cost and Asset ratio.

Schedule Page: 429.3 Line No.: 5 Column: a

- Description: Amount paid to PEC for PESC use of PEC assets (excludes building space) that is attributable to support of PEF.
- Method of Allocation: Direct cost only.

Schedule Page: 429.3 Line No.: 6 Column: a

- Description: Directors and officers liability, fiduciary liability, excess liability and other miscellaneous insurance plans.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.3 Line No.: 7 Column: a

- Description: Calculating, distributing, and recording payroll; maintaining payroll master files; recording time.
- Method of Allocation: Headcount ratio.

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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 429.3 Line No.: 7 Column: c

408.1, 920, 921, 926, 935

Schedule Page: 429.3 Line No.: 8 Column: a

- ☐ Description: Perform routine financial, operational and compliance audits.
- ☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.3 Line No.: 8 Column: c

408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.3 Line No.: 9 Column: a

- ☐ Description: Costs associated with PSSP grants, amortized over vesting period.
- ☐ Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 10 Column: a

- ☐ Description: Review requisitions, issue purchase orders, expediting, Passport system and contract.
- ☐ Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.3 Line No.: 10 Column: c

163, 408.1, 920, 921, 926, 930.2

Schedule Page: 429.3 Line No.: 11 Column: a

- ☐ Description: Taxes associated with property in the name of Service Company; includes leased buildings TPP and PEB, leased aircraft and other minor buildings and parcels of land.
- ☐ Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 12 Column: a

- ☐ Description: Recruiting for active vacancies; pipeline program development and administration (internships, co-ops, college, military, diversity); employment testing.
- ☐ Methods of Allocation: Direct cost and Headcount ratio.

Schedule Page: 429.3 Line No.: 12 Column: c

408.1, 920, 921, 923, 926, 930.1, 930.2

Schedule Page: 429.3 Line No.: 13 Column: a

- ☐ Description: Develop and execute regulatory strategies that ensure acceptable returns in each jurisdiction including cost of service studies; real time pricing, rate administration and transmission tariff issues; ensure recovery of all applicable costs through appropriate pass-thru clauses to include all applicable regulatory filings; planning and coordination of base rate filings.
- ☐ Method of Allocation: Direct cost only.

Schedule Page: 429.3 Line No.: 13 Column: c

107, 408.1, 920, 921, 926, 930.1, 930.2

Schedule Page: 429.3 Line No.: 14 Column: a

- ☐ Description: Lease administration and rent costs for corporate buildings.
- ☐ Methods of Allocation: Direct cost and Headcount ratio.

Schedule Page: 429.3 Line No.: 14 Column: c

418, 904, 921, 923, 931

Schedule Page: 429.3 Line No.: 15 Column: a

- ☐ Description: Costs associated with RSU grants, amortized over vesting period.
- ☐ Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 16 Column: a

- ☐ Description: Supplemental retirement plan and pension restoration for SMC.
- ☐ Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 17 Column: a

- Description: PGN income taxes attributable to PESC resulting from permanent book versus tax differences for non-deductible and partially deductible expenditures; payroll tax burden residual; consulting expenses associated with enterprise tax savings initiatives.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 18 Column: a

- Description: Includes costs associated with Service Company at a business unit level including MICP, ECIP, parking supplement, workers compensation, and service awards.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.3 Line No.: 18 Column: c

107, 408.1, 920, 921, 923, 925, 926, 930.2

Schedule Page: 429.3 Line No.: 19 Column: a

- Description: Owning relations with state-level policy makers, community leaders and politicians, local media outlets, and local economic developers; also includes grassroots and third-party development and Political Action Committee (PAC).
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.3 Line No.: 19 Column: c

408.1, 417.1, 426.1, 426.4, 426.5, 908, 912, 920, 921, 926, 930.1, 935

Schedule Page: 429.4 Line No.: 2 Column: a

- Description: State regulatory and legislative matters; state regulatory affairs support.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.4 Line No.: 2 Column: c

186, 408.1, 426.4, 920, 921, 923, 926

Schedule Page: 429.4 Line No.: 3 Column: a

- Description: Supplier diversity functions.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.4 Line No.: 3 Column: c

408.1, 920, 921,923, 926, 930.2

Schedule Page: 429.4 Line No.: 4 Column: a

- Description: VP Admin/Director; NGG CAP evaluator; self-assessments; root cause analysis; GSA compliance; compliance monitoring and enforcement associated with contracting and/or purchasing evolutions; performance monitoring; process and procedure compliance.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.4 Line No.: 4 Column: c

408.1, 426.5, 920, 921, 923, 926, 930.1, 930.2, 931

Schedule Page: 429.4 Line No.: 5 Column: a

- Description: Federal and State audits including examinations and appeals; sales tax, gross receipts tax, utility and property tax audits.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.4 Line No.: 5 Column: c

408.1, 426.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.4 Line No.: 6 Column: a

- Description: Supporting and documenting accelerated income tax deductions and credit opportunities (repairs, Research & Experimentation (R&E), bonus, pollution

control); contract support and transaction planning (sales tax, contribution in aid of construction, state tax issues)
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.4 Line No.: 6 Column: c
408.1, 920, 921, 923, 926, 930.2

Schedule Page: 429.4 Line No.: 7 Column: a
- Description: Business unit related media relations, consultation, support and issues management; collateral support for regional managers and energy efficiency programs.
- Method of Allocation: Direct cost only.

Schedule Page: 429.4 Line No.: 7 Column: c
107, 186, 408.1, 920, 921, 926

Schedule Page: 429.4 Line No.: 8 Column: a
- Description: Claims services for vehicle damage/injury claims.
- Method of Allocation: Direct cost only.

Schedule Page: 429.4 Line No.: 8 Column: c
408.1, 920, 921, 925, 926

Schedule Page: 429.4 Line No.: 9 Column: a
- Description: Supply chain strategy, vendor management, commodity management, Spend/Market analysis, forecasting.
- Method of Allocation: Three factor ratio.

Schedule Page: 429.4 Line No.: 9 Column: c
163, 408.1, 920, 921, 923, 926, 930.2, 931

Schedule Page: 429.4 Line No.: 10 Column: a
- Description: Wireless voice and data communications hardware, peripherals and services such as cell phones, pagers, blackberries, etc.
- Methods of Allocation: Direct cost using IT Device Rate and Three factor ratio.

Schedule Page: 429.4 Line No.: 10 Column: c
107, 184, 566, 588, 908, 921

Schedule Page: 429.4 Line No.: 11 Column: a
- Description: Provide dedicated data circuits, 800 Service, Local, Long Distance, & Satellite Services.
- Method of Allocation: Headcount ratio.

Schedule Page: 429.4 Line No.: 11 Column: c
408.1, 920, 921, 926

Schedule Page: 429.4 Line No.: 12 Column: a
- Description: This includes charges for misc materials.

Method of Allocation: Direct cost only.

Schedule Page: 429.4 Line No.: 12 Column: c
107, 154, 163, 184, 186, 232, 513, 908

Schedule Page: 429.4 Line No.: 13 Column: a
- Description: This includes goods or services such as Customer Service Management, Performance Solutions, and Utility Business Unit Demand Driven support from the Service Company.

Methods of Allocation: Direct charge, Total Customers Ratio or Headcount Ratio.

Schedule Page: 429.4 Line No.: 13 Column: b
Carolina Power & Light d/b/a Progress Energy Carolinas, Inc.

Schedule Page: 429.4 Line No.: 13 Column: c
186, 408.1, 417.1, 901, 903, 905, 912, 916, 926

Schedule Page: 429.4 Line No.: 14 Column: a

Description: This includes goods or services such as Work Management System and Utility Business Unit Demand Driven support from the Service Company.
Methods of Allocation: Direct Charge or Level of Service Estimate.

Schedule Page: 429.4 Line No.: 14 Column: c

107, 163, 182.3, 186, 408.1, 580, 583, 585, 588, 593, 594, 908, 920, 921, 926

Schedule Page: 429.4 Line No.: 15 Column: a

Description: This includes goods or services such as Executive, administrative and support functions of the Efficiency and Innovative Technology organization and Utility Business Unit Demand Driven support from the Service Company.
Methods of Allocation: Direct Charge or Labor Hour Ratio.

Schedule Page: 429.4 Line No.: 15 Column: c

107, 182.3, 183, 184, 186, 253, 408.1, 417.1, 421, 524, 908, 909, 916, 920, 921, 923, 926, 930.2

Schedule Page: 429.4 Line No.: 16 Column: a

Description: This includes goods or services such as Energy Supply.
Method of Allocation: Maximum Dependable Capacity Ratio.

Schedule Page: 429.4 Line No.: 17 Column: a

Description: This includes goods or services such as Fleet Optimization, Fossil Fuel, Fuel Forecasting, Fuels & Power Optimization, Gas & Oil Trading Administration, Portfolio Management, Power Trading, and Utility Business Unit Demand Driven support from the Service Company.
Methods of Allocation: Direct Charge, Maximum Dependable Capacity Ratio or Level of Service Estimate.

Schedule Page: 429.4 Line No.: 17 Column: c

107, 184, 500, 501, 506, 517, 520, 524, 528, 546, 547, 920, 921, 923,

Schedule Page: 429.4 Line No.: 18 Column: a

Description: This includes goods or services such as Chemistry, Nuclear Material Services, Nuclear Operations, Protective Services, and Radiological and Metallurgical Services.
Methods of Allocation: Direct Charge, Level of Service Estimate or Maximum Dependable Capacity Ratio.

Schedule Page: 429.4 Line No.: 18 Column: c

107, 163, 182.3, 183, 184, 186, 408.1, 500, 506, 512, 513, 517, 519, 520, 524, 528, 529, 530, 532, 549, 908, 920, 921, 923, 926, 930.2

Schedule Page: 429.4 Line No.: 19 Column: a

Description: This includes goods or services such as Nuclear Engineering, Nuclear Engineering Fuel, Nuclear Engineering Management, and Utility Business Unit Demand Driven support from the Service Company.
Methods of Allocation: Direct Charge or Maximum Dependable Capacity Ratio.

Schedule Page: 429.4 Line No.: 19 Column: c

107, 163, 183, 408.1, 500, 513, 514, 517, 518, 520, 524, 528, 529, 530, 531, 532, 921, 926

Schedule Page: 429.5 Line No.: 2 Column: a

Description: This includes goods or services such as Nuclear management costs incurred by the Nuclear Oversight department.
Methods of Allocation: Direct Charge or Maximum Dependable Capacity Ratio.

Schedule Page: 429.5 Line No.: 2 Column: c

107, 408.1, 500, 514, 517, 524, 528, 529, 532, 554, 926

Schedule Page: 429.5 Line No.: 3 Column: a

Description: This includes goods or services such as Nuclear Management costs incurred by the Chief Nuclear Officer that are not directly chargeable to other departments.
Methods of Allocation: Direct Charge or Maximum Dependable Capacity Ratio.

Schedule Page: 429.5 Line No.: 3 Column: c

107, 186, 408.1, 417.1, 511, 512, 513, 514, 519, 520, 523, 524, 528, 529, 530, 531, 532, 554, 570, 592, 920, 921, 923, 926

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	12/31/2011	2011/Q4

FOOTNOTE DATA

Schedule Page: 429.5 Line No.: 4 Column: a

Description: This includes goods or services such as General supervisory services related to the Nuclear IT section.

Method of Allocation: Maximum Dependable Capacity Ratio.

Schedule Page: 429.5 Line No.: 5 Column: a

Description: This includes goods or services such as Power Generation Engineering, Fuels & Power Optimization and Energy Supply Senior Executive for technical support for fossil, hydro and CT, and Utility Business Unit Demand Driven support from the Service Company.

Methods of Allocation: Direct Charge or Maximum Dependable Capacity Ratio.

Schedule Page: 429.5 Line No.: 5 Column: c

107, 184, 186, 408.1, 506, 514, 524, 546, 549, 920, 926

Schedule Page: 429.5 Line No.: 6 Column: a

Description: This includes goods or services such as Transmission & Operations Planning and Utility Business Unit Demand Driven support from the Service Company.

Methods of Allocation: Direct Charge or Level of Service Estimate.

Schedule Page: 429.5 Line No.: 6 Column: c

107, 183, 184, 186, 408.1, 500, 513, 556, 560, 561.1, 561.2, 561.3, 562, 566, 569.1, 569.2, 569.3, 580, 588, 590, 592, 920, 921, 926

Schedule Page: 429.5 Line No.: 7 Column: a

Description: Service Company support of the EIT organization.

Method of Allocation: Direct cost only.

Schedule Page: 429.5 Line No.: 7 Column: c

107, 183, 184, 186, 408.1, 908, 920, 921, 923, 926, 930.2

Schedule Page: 429.5 Line No.: 8 Column: a

- Description: Revenue associated with sub-lease of space in corporate buildings.
- Methods of Allocation: Direct cost and Headcount ratio.

Schedule Page: 429.5 Line No.: 9 Column: a

- Description: Projects to develop new services to meet business technical or regulatory requirements; includes all technical support activities for hardware, software, data, voice, wireless and video communications.
- Methods of Allocation: Direct cost and Three factor ratio.

Schedule Page: 429.5 Line No.: 9 Column: c

107, 182.3, 183, 186, 408.1, 510, 513, 524, 549, 554, 568, 571, 580, 588, 908, 920, 921, 923, 926, 935

Schedule Page: 429.5 Line No.: 10 Column: a

- Description: Maintenance of regional buildings, including mail, cleaning, landscaping, utilities, repairs.
- Methods of Allocation: Direct cost.

Schedule Page: 429.5 Line No.: 10 Column: c

107, 408.1, 920, 921, 926, 935

Schedule	Page No.

Affiliation of Officers and Directors

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2011

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
Vincent Dolan	President and CEO	Board of Trustees	All Children's Hospital
		Board of Directors	Enterprise Florida, Inc.
		Board of Directors	Florida Chamber of Commerce
		Trustee	Florida Chamber Foundation
		Resident Member	Florida Council of 100
		Member	Florida High Tech Corridor Council
		Member	Florida Tax Watch
		Board of Directors	Southeastern Electric Exchange
		Board of Directors, Vice Chair	Tampa Bay Partnership
William D. Johnson	Chairman	Director, Executive Committee: CEO Task Force on Dept of Defense; CEO Task Force on Elec. Transp.; Climate Change Task Force; Policy Committee on Environment; Committee on Gov. & External Affairs	Edison Electric Institute
		Chairman	Carolina Power & Light Co., DBA Progress Energy Carolina's, Inc.
		Chairman	Florida Power Corp., DBA Progress Energy Florida, Inc.
		Director; Executive Committee; Nominating & Corp Gov.; Personnel Dev. & Comp. Committee	Institute of Nuclear Power Operations
		Executive Committee; Nominating Committee	North Carolina Chamber Board
		Board Member	Nuclear Electric Insurance Limited
		Board of Directors; Audit Committee; Executive Committee; Nominating Committee; Organization and Compensation Committee	Nuclear Energy Institute
		Chairman	Progress Capital Holdings
		President	Progress Energy Foundation, Inc.
		Chief Executive Officer	Progress Energy, Inc.
		Chairman	Progress Fuels Corporation
		Chairman	PV Holdings, Inc.
		Chairman	Progress Ventures
Michael Lewis	Senior Vice President	Board Member	Eckerd Youth Alternatives
		Board Member	Eckerd Community Alternatives
		Board Member	American Red Cross
		Board Member	Junior Achievement of West Central Florida
		Board Member	Pinellas Education Foundation
		Board Member	United Way of Tampa Bay

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
Jeff Lyash	Executive Vice President	Chair, Board of Directors	A Baseball Community Coalition
		Board of Directors	Electric Power Research Institute
		Board of Directors, Board of Governors Member	Florida Chamber of Commerce
		Chair, Board of Trustees	Florida Chamber Foundation
		Board of Directors	Rex Healthcare
		Board of Directors	SunTrust Bank North Carolina
John R. McArthur	Senior Vice President	Board of Directors	Carolina Power & Light Company, DBA Progress Energy Carolina's, Inc.
		Board of Directors	Florida Power Corporation
		Board of Directors	Florida Progress Corporation
		Board of Directors	Progress Capital Holdings, Inc.
		Board of Directors	Progress Energy Foundation, Inc.
		Board of Directors	Progress Energy Service Company, LLC
		Board of Directors	Progress Energy, Inc.
		Board of Directors	Progress Fuels Corporation
		Board of Directors	Progress Telecommunications Corp.
		Board of Directors	Progress Ventures, Inc.
		Board of Directors	PV Holdings, Inc.
		Board of Directors	Strategic Resource Solutions
Mark F. Mulhern	Chief Financial Officer	Board of Directors	Capitan Corporation
		Board of Directors	Carofund Inc.
		Board of Directors	Carolina Power & Light Company, DBA Progress Energy Carolina's, Inc.
		Board of Directors	EEI Financial Executive Advisory Committee
		Board of Directors	Florida Power Corporation
		Board of Directors	Florida Progress Corporation
		Board of Directors	Florida Progress Funding Corporation
		Board of Directors	Habitat for Humanity
		Board of Directors	PIH, Inc.
		Board of Directors	PIH Tax Credit Fund, Inc.
		Board of Directors	Progress Capital Holdings, Inc.
		Board of Directors	Progress Energy Foundation, Inc.
		President	Progress Fuels Corporation
		Board of Directors	Progress Telecommunications Corp.
		Board Member	Strategic Resource Solutions
		President	Progress Synfuel Holdings, Inc.
		President	Progress Ventures, Inc.
		President	PV Holdings, Inc.
		President	Carohome, LLC
		President	Kentucky May Coal Co., LLC
		CFO & Sr. Vice President	Progress Energy, Inc.
		CFO & Sr. Vice President	Progress Energy Service Co., LLC
James Scarola	Senior Vice President & Chief Nuclear Officer	Board Member	Parr Shoals Reactor
		Board Member	University of So. Carolina Nuclear Engineering Advisory Board
Paula Sims	Senior Vice President	Board of Trustees	Meredith College
Jeffrey M. Stone	Chief Accounting Officer	None	

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2011

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
Vinny Dolan	Tampa Bay Partnership	$ 100,000	Dues
		$ 7,500	Donation
	The Florida Council of 100	$ 10,816	Dues
	Florida Chamber of Commerce	$ 150,000	Dues
	Enterprise Florida, Inc.	$ 65,000	Sponsorship
	Florida Taxwatch	$ 8,500	Dues
	All Children's Hospital	$ 2,500	Donation
	Southeastern Electric Exchange	$ 28,043	Dues
William Johnson	Institute of Nuclear Power Operations	$ 1,209,540	Dues
	Nuclear Energy Institute	$ 361,851	Dues
Michael Lewis	Junior Achievement	$ 16,720	Donation
Jeff Lyash	Electric Power Research Institute	$ 2,073,360	Dues
Mark Mulhern	Habitat for Humanity	$ 50,800	Donation

Annual Report versus Regulatory Assessment Fee Return

***Company:** Progress Energy Florida Inc.*
For the Year Ended December 31, 2011

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)	$ 4,240,027,159	$ 40,343,230	$ 4,199,683,929	$ 4,240,027,159	$ 40,343,230	$ 4,199,683,929	$ -
2	Sales for Resale (447)	239,145,300	239,145,300	-	239,145,300	239,145,300	-	0
3	Total Sales of Electricity	4,479,172,459	279,488,530	4,199,683,929	4,479,172,459	279,488,530	4,199,683,929	0
4	Provision for Rate Refunds (449.1)	(287,939,887)	60,113	(288,000,000)	60,113	60,113	-	(288,000,000) (1)
5	Total Net Sales of Electricity	4,191,232,572	279,548,643	3,911,683,929	4,479,232,572	279,548,643	4,199,683,929	(288,000,000)
6	Total Other Operating Revenues (450-456)	177,809,728	67,918,507	109,891,221	177,809,728	67,918,507	109,891,221	-
7	Other (Specify)							
8								
9								
10	**Total Gross Operating Revenues**	$ 4,369,042,300	$ 347,467,150	$ 4,021,575,150	$ 4,657,042,300	$ 347,467,150	$ 4,309,575,150	$ (288,000,000)

Notes: (1) Difference reflects a $288 million dollar refund under the terms of the 2012 settlement agreement with the Florida Public Service Commission, Docket 120022, Order PSC-12-0104-FOF-EI recorded in 2011. This adjustment was appropriately ommitted from the 2011 RAF return. The adjustment will be reflected in the RAF return in the future as the refunds are applied.

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

For the Year Ended December 31, 2011

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)
1/1/2011	Retroactive to April 15, 2010, PTC's ownership interest in PT Holding Company LLC (PTH) increased to 52.9412%. This increase was due to PTH's purchase and redemption of its restricted units held by all but two of its individual members.
4/1/2011	Effective November 4, 2010, CP&L's interest in Intellon Corp was sold.
4/1/2011	Retroactive to January 1, 2011, CaroFinancial Inc. was dissolved.
4/1/2011	Retroactive to the date of acquisition, April 28, 2008, Florida Power Corporation's ownership interest in SanGroup, LLC is 45.0482%. The initial ownership interest (53.0049%) included in the legal entity chart was the expected ownership interest before the operating agreement was available.
7/1/2011	As of March 4, 2011, CP&L's ownership interest in Microcell Corporation is 3.4%. The increase is due to additional investment in shares of the entity.

Analysis of Diversification Activity
New or Amended Contracts with Affiliated Companies

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2011

Provide a synopsis of each new or amended contract, agreement, or arrangement with affiliated companies for the purchase, lease, or sale of land, goods, or services (excluding tariffed items). The synopsis shall include, at a minimum, the terms, price, quantity, amount, and duration of the contracts.

Name of Affiliated Company (a)	Synopsis of Contract (b)
No new or amended affiliated contracts in 2011.	

Analysis of Diversification Activity

Individual Affiliated Transactions in Excess of $500,000

Company: Progress Energy Florida Inc.

For the Year Ended December 31, 2011

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)
Carolina Power & Light Company (d/b/a Progress Energy Carolinas) (as service provider)	Recurring monthly shared utility functions and services excluding Smart Grid (listed separately below). See page 457 for description.	$ 33,579,067
Carolina Power & Light Company (d/b/a Progress Energy Carolinas) (as service provider)	Recurring reimbursements of Smart Grid project expenses in efficiency and innovative technology. Included in page 457 description.	$ 23,565,654
Carolina Power & Light Company (d/b/a Progress Energy Carolinas) (as customer)	Recurring monthly shared utility functions and services. See page 457 for description.	$ 11,742,942
Progress Energy Service Company (as service provider)	Recurring monthly Service Company functions and services. See page 457 for description.	$ 160,235,727
Progress Energy Service Company (as customer)	Recurring monthly shared functions and services. See page 457 for description.	$ 1,685,125

Analysis of Diversification Activity
Summary of Affiliated Transfers and Cost Allocations

Company: Progress Energy Florida Inc.
For the Year Ended December 31, 2011

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)
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Direct and indirect charges for shared utility functions and services such as customer & market services, power operations, nuclear generation, transmission operations & planning, energy delivery, executive management, corporate development, corporate relations & administrative services, misc materials, and sale of personal computers.	Utility Service Agreement 1/1/2001	S	1460001	$ 11,742,942
Carolina Power & Light Company (d/b/a Progress Energy Carolinas)	Direct and indirect charges for shared utility functions and services such as customer & market services, distribution engineering & operations, efficiency and innovative technology, energy supply, fuels & power optimization, nuclear operations, nuclear engineering, nuclear oversight, nuclear generation, nuclear information technology, power generation and transmission & operations planning.	Utility Service Agreement 1/1/2006	P	2340001	$ 57,144,721
PT Holding Company LLC	Network Services, Land Lease, Revenue Sharing	Master Service and Wireless Attachment Agreements - 12/19/2003	S	1460071	$ 2,102,430
Peak Tower, LLC	Land Lease	Land Lease Agreement 8/1/2010	S	1460074	$ 11,000
Progress Energy Service Company LLC	Labor and associated expenses, materials.	Utility Service Agreement 1/1/2001; Amendment to Article IV effective 10/18/2007	S	1460098	$ 1,685,125
Progress Energy Service Company LLC	Direct and indirect charges for shared corporate functions including accounting, audit, corporate communications, corporate planning, corporate relations, corporate services, executive management, external relations, human resources, information technology & telecommunications, investor relations, legal, state public affairs & economic development, supply chain services, tax, treasury & risk management, and service company corporate services. Plus direct operational support provided upon request from affiliate in support of affiliate projects. Excludes convenience payments and pay agent transactions.	Utility Service Agreement 12/1/2000	P	2340098	$ 160,235,727

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

Company:* *Progress Energy Florida Inc.

For the Year Ended December 31, 2011

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:		$	$	$	$	$	
Total						$	
Sales to Affiliates:		$	$	$	$	**Sales Price**	
Progress Energy Carolinas	190 Desktop PCs	253,450.43	120,185.66	133,264.77	271,486.54	133,264.77	Yes
Total						**133,264.77**	

Company: Progress Energy Florida, Inc.

For the Year Ended December 31, 2011

List employees earning more than $30,000 annually transferred to/from the utility to/from an affiliate company.

Company Transferred From	Company Transferred To	Old Job Assignment	New Job Assignment	Transfer Permanent or Temporary and Duration
FPC	CPL	Siting & Baseload Proj Spec	Siting & Baseload Proj Spec	Permanent
FPC	CPL	Nuclear CAP Coordinator	Nuc Work Week Coord	Permanent
SVC	FPC	Environmental Specialist	Environmental Specialist	Permanent
FPC	SVC	Environmental Specialist	Environmental Specialist	Permanent
FPC	CPL	Lead Proj Controls Spec	Lead Proj Controls Spec	Permanent
FPC	CPL	Nuc Tech Asst I	Nuc Tech Asst I	Permanent
FPC	SVC	Admin Assistant I	Assoc Procurement Spec (INT)	Permanent
CPL	FPC	Mgr-Nuclear Oversight	NGG Plant General Mgr (INT)	Permanent
CPL	FPC	Siting & Baseload Proj Spec	Siting & Baseload Proj Spec	Permanent
FPC	CPL	Supv-SupplierPerformOversight	Nuc QA Codes and Stands Spec	Permanent
FPC	SVC	Energy Efficiency Coord I	Sr Business Tech Analyst	Permanent
CPL	FPC	Human Performance Leader	Sr Joint Use Spec	Permanent
FPC	CPL	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
CPL	FPC	Nucl Non-Tech Perf Imp Coord	Nucl OE/SA/Benchmark Coord	Permanent
SVC	FPC	Sr Bus Fin Anlyst	Sr Bus Fin Analyst-R(07/13)	Permanent
FPC	CPL	Mgr-Transmission Area Maint	Mgr-TOPD Work Mgmt (IO)	Permanent
FPC	SVC	Sr Engr	Sr Regulatory Spec-R (05/12)	Permanent
CPL	FPC	Engineer II	Asst Nucl Auxiliary Oper	Permanent
FPC	SVC	Sr Work Mgmt Spec	Supv-T&D Florida Sourcing	Permanent
FPC	CPL	NGG Plant General Mgr	Dir-Nucl Major Projects (INT)	Permanent
FPC	CPL	Nucl Aux Operator	Aux Oper B-Nuc	Permanent
FPC	CPL	Gen Mgr-Suncoast-PGF	FPO-Special Projects-R (02/13)	Permanent
FPC	CPL	Sr Craft/Technical Trainer	Sr Craft/Technical Trainer	Permanent
FPC	CPL	Scrubber Oper	Control Oper	Permanent
CPL	FPC	Storekeeper B	Nuc Materials Assistant	Permanent
FPC	CPL	Sr Nuc Tech Trng Instructor	Supv-Env & Chem	Permanent
CPL	FPC	Sr Engr Technical Supt Spec	Sr Engr Technical Supt Spec	Permanent
FPC	SVC	Gen Mgr-Smart Grid Projects	Gen Mgr-Materials Mgmt & Svcs	Permanent
SVC	FPC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
SVC	FPC	Sr Tech Suppt Anlyst-IT	Sr Engr Technical Supt Spec	Permanent
FPC	CPL	GIS Tech I	Configuration Mgmt Spec-NGG	Permanent
FPC	CPL	Temporary Student Worker	Engineer III	Permanent
FPC	CPL	Sr Nuclear Security Spec	Sr Nuclear Security Spec	Permanent
FPC	CPL	Sr Proj Controls Spec	Sr Proj Controls Spec	Permanent
CPL	FPC	Control Oper	Scrubber Oper	Permanent
SVC	FPC	Sr Bus Fin Anlyst	Sr Bus Ops Process Analyst	Permanent
CPL	FPC	Sr Security Spec	Mgr Inv and Phys Sec-R(12/12)	Permanent
FPC	CPL	Mgr-Nuc Project Controls	Mgr-Nuclear Oversight	Permanent
CPL	FPC	Plant Mgr-Lee/Wayne CT	Gen Mgr-Suncoast-PGF	Permanent
FPC	CPL	Nucl OE/SA/Benchmark Coord	Nucl OE/SA/Benchmark Coord	Permanent
FPC	SVC	Sr Environmental Specialist	Sr Environmental Specialist	Permanent
CPL	FPC	Lead Environmental Specialist	Lead Environmental Specialist	Permanent
FPC	SVC	Env Compl Prog Mgr	Env Compl Prog Mgr	Permanent
SVC	FPC	CBE Leader	Sr Bus Ops Proc Analyst (INT)	Permanent
FPC	CPL	GIS Tech I	Engr Tech I-Nuc	Permanent
CPL	FPC	Lead Config Mgmt Spec-NGG	NGG Site Trending Prog Coord	Permanent
CPL	FPC	Dir-Nuclear Major Projects	Gen Mgr-Major Projects-CR3	Permanent
FPC	CPL	Sr Engr	Lead Engr	Permanent
SVC	FPC	Lead Project Assurance Advisor	Lead Project Assurance Advisor	Permanent
CPL	FPC	Enrgy Mgmt Sys Supp Spec	Sr Business Tech Analyst	Permanent
FPC	CPL	Sr Work Mgmt Spec	Nucl Switchyard Coord	Permanent
CPL	FPC	DCC Shift Supervisor	Supv-Power Systems Ops	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, 2011

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)
Rent from Electric Properties	4540001	Regulated
Managed Services	4170001	Non-Regulated
Turnkey Solutions	4170001	Non-Regulated
Power Quality Services	4170001	Non-Regulated
Homewire	4170001	Non-Regulated
Water Heater Repair	4170001	Non-Regulated
All-Connect	4170001	Non-Regulated
Lighting	4170001	Non-Regulated
Home Service Advisor	4170001	Non-Regulated
Infrared Scanning Services	4170001	Non-Regulated
High Voltage Services	4170001	Non-Regulated
Distribution Engineering Services	4170001	Non-Regulated
Vegetation Services	4170001	Non-Regulated
Transformer Services	4170001	Non-Regulated
Material Solutions	4170001	Non-Regulated
Joint Trenching	4170001	Non-Regulated
Overhead, Underground and Submarine Distribution	4170001	Non-Regulated
Transmission Design	4170001	Non-Regulated
Transmission Construction & Maintenance	4170001	Non-Regulated
Substation Design, Construction & Maintenance	4170001	Non-Regulated
System Protection & Control, Fiber Optic & Meter Services	4170001	Non-Regulated

Nonutility Property (Account 121)

Company: Progress Energy Florida, Inc.

For the Year Ended December 31, 2011

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 **(* See Note)**	178,864	(124,554)	54,310
Not Previously Devoted to Public Service			
Land - Volusia County, Florida	1,622,391		1,622,391
Equipment - Meters System (Florida)	5,423,549		5,423,549
Equipment - Walk of Fame, St. Pete, FL	1,380,193		1,380,193
Other **(* See Note)**	675,480	(139)	675,341
Generators on Customer premises	799,109		799,109
* **Note:** The dollar change between beginning and ending year balance in these categories is due to retirements.			
Totals	$ 10,391,789	$ (124,693)	$ 10,267,096

Number of Electric Department Employees

Company: Progress Energy Florida, Inc.
For the Year Ended December 31, 2011

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)	**10/23/2011**
2. Total Regular Full-Time Employees	**3,829**
3. Total Part-Time and Temporary Employee	**216**
4. Total Employees	**4,045**

Details

Regular Part Time:	6
Temp Full Time:	210
Temp Part Time:	0

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Company: Progress Energy Florida, Inc.
For the Year Ended December 31, 2011

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

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

(b) Miscellaneous Income Deductions -- Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than 5% of each account total for the year (or $1,000, whichever is greater) may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430) -- For each associated company to which interest on debt was incurred during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) -- Report particulars (details) including the amount and interest rate for other interest charges incurred during the year.

Item	Amount
Account 426 - Miscellaneous Income Deductions	
Donations	
Civic & Community Organizations	280,418.00
Cultural & Art Organizations	102,882.50
Economic Development	235,045.97
Education Related Contributions	-
Educational Institutions & Charitable Organizations	771,896.07
Health & Human Services Contributions	180,924.87
Other	259,248.26
Subtotal Accounts 426100F, 4261013, 4261014, 426180T	1,830,415.67
Investment in Company Owned Life Insurance	(397,561.09)
Subtotal Accounts 4262016	(397,561.09)
Penalties	166,889.42
Subtotal Accounts 4263001	166,889.42
Certain Civic, Political & Related Activities	3,160,835.33
Subtotal Accounts 4264200	3,160,835.33
Other Deductions	21,960,546.03
Subtotal Accounts 4265001, 4265007, 4265200	21,960,546.03
Total Miscellaneous Income Deductions - Account 426	26,721,125.36
Account 430 - Interest of Debt to Associated Companies	
Money Pool (Avg Rate 0.321%)	35,652.16
Total Interest on Debt to Associated Companies - Account 430	35,652.16
Account 431 - Other Interest Expense	
Commitment Fees (4310010)	1,750,000.00
Other Interest Expense (4310011)	233,605.05
Customer Deposits - Rate 6 to 7% per annum	13,518,281.42
Interest related to Municipal Utility Tax Audit Settlement - Rate 1% per month	25,756.70
Interest related to Projected Tax Deficiency on various audit issues - Rate 5.97%	(15,601,110.59)
Total Other Interest Expense - Account 431	(73,467.42)

Budgeted and Actual In-Service Costs of Nuclear Power Plant

Company: Progress Energy - Florida **Redacted**
For the Year Ended December 31, 2011

Report the budgeted and actual costs as compared to the estimated in-service costs of the proposed power plant as provided in the petition for need determination or revised estimate as necessary. Per Rule 25-6.0423(8)(f)

Item	Actual Costs as of December 31, 2011	Remaining Budgeted Costs to Complete Plant:	Total Estimated Cost of Plant	Note 1 Estimated Cost provided in the Petition for Need Determination (or revised estimate as necessary)
Plant Name: Levy County Nuclear Unit 1 and 2				
Licensing/Permits/Authorizations/Legal	[redacted]			$ -
Site/Site Preparation	[redacted]			$ -
Related Facilities	[redacted]			$ -
Generation Plant	[redacted]			$ 10,516,097,000
Transmission Facilities	[redacted]			$ 2,446,841,000
Total	$ 674,528,576	$ 17,755,034,125	$ 18,429,562,701	$ 12,962,938,000

Note 1: These amounts are based on our Need Determination which was filed March 11, 2008. At that point PEF did not have negotiated or signed contracts in place. Therefore the estimates provided are high level and only broken out between generation and transmission as presented in the Need Petition. As the project continues PEF will have better estimates and contracts in place.

Note 2: Costs included herein are exclusive of AFUDC and Carrying Costs as well as initial fuel load costs.

Deloitte.

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INDEPENDENT AUDITORS' REPORT

Florida Power Corporation d/b/a Progress Energy Florida, Inc.
St. Petersburg, Florida

We have audited the balance sheet—regulatory basis of Florida Power Corporation d/b/a Progress Energy Florida, Inc. (the "Company") as of December 31, 2011, and the related statements of income—regulatory basis, retained earnings—regulatory basis, and cash flows—regulatory basis for the year then ended, 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 on 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 regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2011, and the results of its operations and its cash flows for the year then ended 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 the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

February 28, 2012

Member of
Deloitte Touche Tohmatsu Limited

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
1	**STEAM PRODUCTION**						
2	**ANCLOTE**						
3	311 STRUCTURES & IMPROVEMENTS	1.9	38,171,190	179,859	(342,925)	-	38,008,124
4	312 BOILER PLANT EQUIPMENT	2.2	106,607,405	1,081,180	(605,394)	-	107,083,191
5	314 TURBOGENERATOR UNITS	2.8	115,891,873	986,178	159,478	-	117,037,529
6	315 ACCESSORY ELECTRIC EQUIPMENT	1.6	26,889,610	135,434	(542,638)	-	26,482,406
7	316.1 MISC POWER PLANT EQUIPMENT	1.7	7,398,486	301,602	233,082	-	7,933,170
8	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	121,812	-	(171,684)	-	(49,873)
9	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	345,201	-	(208,660)	-	136,541
10	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		507,681	-	-	-	507,681
11							
12	**TOTAL ANCLOTE**		295,933,256	2,684,253	(1,478,741)	-	297,138,768
13							
14	**BARTOW**						
15	311 STRUCTURES & IMPROVEMENTS		-	-	-	-	-
16	312 BOILER PLANT EQUIPMENT		-	-	-	-	-
17	314 TURBOGENERATOR UNITS		-	-	-	-	-
18	315 ACCESSORY ELECTRIC EQUIPMENT		-	-	-	-	-
19	316 MISC POWER PLANT EQUIPMENT		-	-	-	-	-
20	316 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-
21	316 MISC POWER PLANT EQUIPMENT (7 YEAR)		-	-	-	-	-
22	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		2,610,937	-	-	-	2,610,937
23							
24	**TOTAL BARTOW**		2,610,937	-	-	-	2,610,937
25							
26	**BARTOW-ANCLOTE PIPELINE**						
27	311 STRUCTURES & IMPROVEMENTS	1.8	1,166,120	8,483	-	-	1,174,603
28	312 BOILER PLANT EQUIPMENT	2.6	17,317,453	11,022	(1,564)	-	17,326,911
29	315 ACCESSORY ELECTRIC EQUIPMENT	1.4	2,075,155	-	-	-	2,075,155
30	316.1 MISC POWER PLANT EQUIPMENT	3.4	147,781	135,074	-	-	282,855
30	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	8,731	-	-	-	8,731
31							
32	**TOTAL BARTOW-ANCLOTE PIPELINE**		20,715,240	154,578	(1,564)	-	20,868,254
33							
34	**CRYSTAL RIVER 1&2**						
35	311 STRUCTURES & IMPROVEMENTS	2.2	76,117,418	669,111	(191,362)	-	76,595,167
36	312 BOILER PLANT EQUIPMENT	3.7	197,992,306	4,734,725	(3,053,235)	(2,510,118)	197,163,678
37	314 TURBOGENERATOR UNITS	2.5	127,221,703	2,322,846	(2,016,264)	-	127,528,285
38	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	35,839,074	1,515,124	87,226	92,101	37,533,526
39	316.1 MISC POWER PLANT EQUIPMENT	2.1	8,000,305	156,484	(270,538)	-	7,886,251
40	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	(20,350)	-	171,684	-	151,334
41	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	451	398	208,660	-	209,509
42	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		4,923,474	-	-	-	4,923,474
43							
44	**TOTAL CRYSTAL RIVER 1&2**		450,074,380	9,398,688	(5,063,828)	(2,418,017)	451,991,224

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
45							
46	**CRYSTAL RIVER 4&5**						
47	311 STRUCTURES & IMPROVEMENTS	1.5	284,530,900	9,547,179	(382,506)	-	293,695,573
48	312 BOILER PLANT EQUIPMENT	2.5	1,627,126,960	(15,184,447)	(11,557,809)	(1,500,000)	1,598,884,704
49	314 TURBOGENERATOR UNITS	1.0	252,152,020	23,132,376	(5,171,187)	-	270,113,210
50	315 ACCESSORY ELECTRIC EQUIPMENT	1.0	194,328,422	5,687,380	(96,823)	-	199,918,979
51	316.1 MISC POWER PLANT EQUIPMENT	2.1	13,670,469	1,731,283	(18,830)	747,203	16,130,125
52	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	233,211	-	-	-	233,211
53	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	665,951	-	-	-	665,951
54	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
55							
56	**TOTAL CRYSTAL RIVER 4&5**		2,372,707,934	24,913,771	(17,227,155)	(752,797)	2,379,641,753
57							
58	**SUWANNEE**						
59	311 STRUCTURES & IMPROVEMENTS	2.3	5,256,455	131,354	(32,701)	-	5,355,108
60	312 BOILER PLANT EQUIPMENT	3.1	16,180,954	97,469	(11,113)	-	16,267,310
61	314 TURBOGENERATOR UNITS	2.9	13,346,438	107,938	(29,991)	-	13,424,385
62	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	2,760,875	-	-	-	2,760,875
63	316.1 MISC POWER PLANT EQUIPMENT	2.9	756,027	44,816	-	-	800,843
64	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	7,170	-	-	-	7,170
65	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	19,874	-	-	-	19,874
66	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		1,726,484	-	-	-	1,726,484
67							
68	**TOTAL SUWANNEE**		40,054,278	381,576	(73,805)	-	40,362,049
69							
70	**RAIL CARS**	3.4	32,738,780	-	-	-	32,738,780
71							
72	**CRYSTAL RIVER 1&2 COALPILE**	3.7	996,433	-	-	-	996,433
73							
74	**CRYSTAL RIVER 4&5 COALPILE**	2.5	3,481,411	(1,753,978)	-	-	1,727,433
75							
76	**316.2 SYSTEM ASSETS 316.2 (5 YEAR)**	20.0	600,702	-	-	-	600,702
77	**316.3 SYSTEM ASSETS 316.3 (7 YEAR)**	14.3	424,305	-	-	-	424,305
78							
79	**TOTAL STEAM PRODUCTION**		3,220,337,656	35,778,888	(23,845,092)	(3,170,814)	3,229,100,638
80							
81							

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
82	**NUCLEAR PRODUCTION**						
83	**CRYSTAL RIVER#3**						
84	321 STRUCTURES & IMPROVEMENTS	1.5	239,533,190	39,034,630	(1,205,508)	(810,781)	276,551,531
85	322 REACTOR PLANT EQUIPMENT	3.3	298,964,575	3,628,941	(2,951,962)	-	299,641,555
86	323 TURBOGENERATOR UNITS	1.2	95,486,285	1,821,189	(652,937)	-	96,654,537
87	324 ACCESSORY ELECTRIC EQUIPMENT	1.4	184,564,615	971,184	(3,309,161)	-	182,226,638
88	325.1 MISCELLANEOUS POWER EQUIPMENT	1.7	43,381,944	760,927	(12,031,472)	(747,203)	31,364,195
89	325.2 MISCELLANEOUS POWER EQUIPMENT (5 YEAR)	20.0	1,889,821	114,812	-	-	2,004,633
90	325.3 MISCELLANEOUS POWER EQUIPMENT (7 YEAR)	14.3	4,730,524	516,519	-	-	5,247,043
91	326 ASSET RETIREMENT COSTS FOR NUCLEAR PROD PLANT		-	-	-	-	-
92							
93	**TOTAL NUCLEAR**		868,550,955	46,848,201	(20,151,040)	(1,557,984)	893,690,131
94							
95	**OTHER PRODUCTION**						
96	**AVON PARK PEAKERS**						
97	341 Structures and Improvements	0.6	458,334	1,406	-	-	459,739
98	342 Fuel Holders, Products, and Accessories	4.8	630,520	-	-	-	630,520
99	343 Prime Movers	3.0	5,988,706	46,586	(70,119)	-	5,965,174
100	344 Generators	0.1	1,807,566	-	-	-	1,807,566
101	345 Accessory Electric Equipment	0.5	1,167,291	-	-	-	1,167,291
102	346 Misc. Power Plant Equipment	3.2	71,944	-	-	-	71,944
103	346.2 Misc. Power Plant Equipment (5 Year)	20.0	26,451	-	-	-	26,451
104	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
105							
106	**TOTAL AVON PARK PEAKERS**		10,150,812	47,992	(70,119)	-	10,128,685
107							
108	**BARTOW**						
109	341 Structures and Improvements	1.7	1,076,349	27,552	-	-	1,103,900
110	342 Fuel Holders, Products, and Accessories	3.0	3,157,428	-	(3,206)	-	3,154,222
111	343 Prime Movers	1.6	14,261,185	288,748	-	-	14,549,933
112	344 Generators	2.1	7,439,841	-	-	-	7,439,841
113	345 Accessory Electric Equipment	1.8	2,177,934	-	-	-	2,177,934
114	346 Misc. Power Plant Equipment	0.4	190,378	5,116	-	-	195,495
115	346.3 Misc. Power Plant Equipment (7 Year)	14.3	1,240	-	-	-	1,240
116							
117	**TOTAL BARTOW**		28,304,355	321,417	(3,206)	-	28,622,565
118							
119	**BARTOW 4x1**						
120	341 Structures and Improvements	3.3	60,034,021	1,960,324	(71,603)	-	61,922,742
121	342 Fuel Holders, Products, and Accessories	3.2	26,160,989	(2,539,060)	9,896,341	-	33,518,270
122	343 Prime Movers	3.3	450,005,887	16,750,103	(16,103,433)	-	450,652,558
123	344 Generators	3.3	49,832,617	(4,167,807)	-	-	45,664,811
124	345 Accessory Electric Equipment	3.3	21,991,425	12,385,663	-	-	34,377,088
125	346 Misc. Power Plant Equipment	3.3	20,659,163	(2,583,302)	(17,275)	-	18,058,586

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
126							
127	**TOTAL BARTOW 4x1**		628,684,103	21,805,922	(6,295,970)	-	644,194,054
128							
129	**BAYBORO**						
130	341 Structures and Improvements	1.0	1,692,332	-	-	-	1,692,332
131	342 Fuel Holders, Products, and Accessories	3.0	1,853,803	21,904	-	-	1,875,706
132	343 Prime Movers	2.3	16,340,540	1,065,069	(329,460)	-	17,076,148
133	344 Generators	1.4	3,579,059	-	-	-	3,579,059
134	345 Accessory Electric Equipment	1.8	1,196,827	-	-	-	1,196,827
135	346 Misc. Power Plant Equipment	1.1	424,630	10,184	(5,701)	-	429,113
136	346.2 Misc. Power Plant Equipment (5 Year)	20.0	29,609	-	-	-	29,609
137	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
138							
139	**TOTAL BAYBORO**		25,116,799	1,097,157	(335,161)	-	25,878,795
140							
141	**DEBARY (NEW)**						
142	341 Structures and Improvements	3.3	4,687,604	-	-	-	4,687,604
143	342 Fuel Holders, Products, and Accessories	4.0	7,966,882	8,097	(7,806)	-	7,967,172
144	343 Prime Movers	3.7	65,558,965	1,695,550	(1,892,003)	-	65,362,512
145	344 Generators	3.3	18,375,745	131,402	(67,725)	-	18,439,421
146	345 Accessory Electric Equipment	3.4	5,141,351	139,310	(57,107)	-	5,223,553
147	346 Misc. Power Plant Equipment	4.2	838,168	49,449	-	-	887,617
148							
149	**TOTAL DEBARY (NEW)**		102,568,714	2,023,807	(2,024,642)	-	102,567,879
150							
151	**DEBARY (OLD)**						
152	341 Structures and Improvements	2.7	5,008,220	17,713	(5,588)	-	5,020,345
153	342 Fuel Holders, Products, and Accessories	2.6	8,901,194	1,210,622	-	-	10,111,816
154	343 Prime Movers	3.0	28,337,111	1,030,869	(285,436)	-	29,082,544
155	344 Generators	2.4	9,457,806	-	-	-	9,457,806
156	345 Accessory Electric Equipment	2.5	5,818,551	30,717	(35,422)	-	5,813,846
157	346 Misc. Power Plant Equipment	3.3	860,094	23,714	(1,501)	-	882,307
158	346.2 Misc. Power Plant Equipment (5 Year)	20.0	19,741	-	-	-	19,741
159							
160	**TOTAL DEBARY (OLD)**		58,402,717	2,313,635	(327,947)	-	60,388,405
161							
162	**HIGGINS**						
163	341 Structures and Improvements	2.9	754,453	-	-	-	754,453
164	342 Fuel Holders, Products, and Accessories	5.4	1,983,048	-	-	-	1,983,048
165	343 Prime Movers	2.9	11,071,125	75,920	(51,166)	-	11,095,879
166	344 Generators	2.9	2,640,150	-	-	-	2,640,150
167	345 Accessory Electric Equipment	3.2	2,671,421	-	-	-	2,671,421
168	346 Misc. Power Plant Equipment	4.6	284,880	-	-	-	284,880
169	346.2 Misc. Power Plant Equipment (5 Year)	20.0	16,437	-	-	-	16,437
170							

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
171			19,421,514	75,920	(51,166)	-	19,446,268
172	**TOTAL HIGGINS**						
173							
174	**HINES #1**						
175	341 Structures and Improvements	2.9	45,567,823	345,108	(119,357)	-	45,793,574
176	342 Fuel Holders, Products, and Accessories	3.2	16,873,218	(204,984)	-	-	16,668,234
177	343 Prime Movers	3.2	190,680,360	24,776,949	(20,366,410)	-	195,090,899
178	344 Generators	2.9	44,807,805	-	-	-	44,807,805
179	345 Accessory Electric Equipment	3.2	22,222,007	308,625	(212,311)	-	22,318,321
180	346 Misc. Power Plant Equipment	3.1	4,237,089	288,013	-	-	4,525,102
181	346.2 Misc. Power Plant Equipment (5 Year)	20.0	217,802	(42,361)	-	-	175,441
182							
183	**TOTAL HINES #1**		324,606,105	25,471,349	(20,698,078)	-	329,379,377
184							
185	**HINES #2**						
186	341 Structures and Improvements	3.7	46,763,091	(27,458,254)	(11,468)	-	19,293,369
187	342 Fuel Holders, Products, and Accessories	3.2	12,953,803	-	-	-	12,953,803
188	343 Prime Movers	3.3	125,222,207	26,328,062	(21,087,587)	-	130,462,683
189	344 Generators	2.9	39,325,539	3,204,933	(2,955,771)	-	39,574,701
190	345 Accessory Electric Equipment	3.2	17,793,092	8,931	-	-	17,802,022
191	346 Misc. Power Plant Equipment	3.1	2,735,874	-	-	-	2,735,874
192							
193	**TOTAL HINES #2**		244,793,606	2,083,672	(24,054,826)	-	222,822,453
194							
195	**HINES #3**						
196	341 Structures and Improvements	3.7	10,266,058	87,470	-	-	10,353,529
197	342 Fuel Holders, Products, and Accessories	3.2	15,119,886	-	-	-	15,119,886
198	343 Prime Movers	3.3	144,732,626	13,008,161	(3,602,406)	-	154,138,382
199	344 Generators	2.9	51,074,512	449,578	-	-	51,524,090
200	345 Accessory Electric Equipment	3.2	21,553,487	(70)	-	-	21,553,417
201	346 Misc. Power Plant Equipment	3.1	1,483,987	-	-	-	1,483,987
202							
203	**TOTAL HINES #3**		244,230,557	13,545,139	(3,602,406)	-	254,173,290
204							
205	**HINES #4**						
206	341 Structures and Improvements	3.7	11,951,276	682	-	-	11,951,959
207	342 Fuel Holders, Products, and Accessories	3.2	7,337,041	38,485	-	-	7,375,526
208	343 Prime Movers	3.3	183,510,109	17,113,073	(11,941,246)	-	188,681,935
209	344 Generators	2.9	45,072,225	-	-	-	45,072,225
210	345 Accessory Electric Equipment	3.2	22,592,398	21,306	-	-	22,613,704
211	346 Misc. Power Plant Equipment	3.1	7,197,230	-	-	-	7,197,230
212							
213	**TOTAL HINES #4**		277,660,279	17,173,546	(11,941,246)	-	282,892,579
214							
215	**INTERCESSION CITY P1-6**						

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
216	341 Structures and Improvements	2.9	3,792,584	9,962	-	-	3,802,546
217	342 Fuel Holders, Products, and Accessories	6.6	3,760,042	-	-	-	3,760,042
218	343 Prime Movers	2.7	23,901,549	3,093,787	(1,330,370)	-	25,664,967
219	344 Generators	2.6	4,716,975	-	-	-	4,716,975
220	345 Accessory Electric Equipment	3.1	3,502,233	13,391	(23,636)	-	3,491,988
221	346 Misc. Power Plant Equipment	5.5	1,154,543	(13,264)	(334)	-	1,140,945
222	346.3 Misc. Power Plant Equipment (7 Year)	14.3	1,299	-	-	-	1,299
223							
224	**TOTAL INTERCESSION CITY P 1-6**		40,829,224	3,103,877	(1,354,340)	-	42,578,761
225							
226	**INTERCESSION CITY (NEW) P7-10**						
227	341 Structures and Improvements	2.5	9,415,162	7,875	(1,188)	-	9,421,849
228	342 Fuel Holders, Products, and Accessories	2.8	7,086,174	14,623	(8,361)	-	7,092,435
229	343 Prime Movers	2.6	63,101,383	5,701,993	(4,183,614)	-	64,619,763
230	344 Generators	2.5	17,748,539	-	-	-	17,748,539
231	345 Accessory Electric Equipment	2.5	5,219,354	2,554	(576)	-	5,221,333
232	346 Misc. Power Plant Equipment	2.3	1,036,448	5,818	-	-	1,042,266
233	346.2 Misc. Power Plant Equipment (5 Year)	20.0	48,968	-	-	-	48,968
234							
235	**TOTAL INTERCESSION CITY P 7-10**		103,656,028	5,732,863	(4,193,739)	-	105,195,152
236							
237	**INTERCESSION CITY P11**						
238	341 Structures and Improvements	4.0	1,261,419	2,626	(2,402)	-	1,261,642
239	342 Fuel Holders, Products, and Accessories	4.4	1,379,318	-	-	-	1,379,318
240	343 Prime Movers	4.6	14,069,090	-	-	-	14,069,090
241	344 Generators	4.0	2,664,079	-	-	-	2,664,079
242	345 Accessory Electric Equipment	4.0	3,619,321	136,720	(132,464)	-	3,623,577
243	346 Misc. Power Plant Equipment	3.8	188,206	-	-	-	188,206
244							
245	**TOTAL INTERCESSION CITY P 11**		23,181,432	139,345	(134,866)	-	23,185,911
246							
247	**INTERCESSION CITY P12-14**						
248	341 Structures and Improvements	2.8	1,426,366	19,823	(11,673)	-	1,434,516
249	342 Fuel Holders, Products, and Accessories	3.0	4,259,660	17,890	(3,796)	-	4,273,754
250	343 Prime Movers	2.9	60,095,889	11,840,959	(7,294,080)	-	64,642,768
251	344 Generators	2.5	16,681,378	-	-	-	16,681,378
252	345 Accessory Electric Equipment	2.6	6,886,452	-	-	-	6,886,452
253							
254	**TOTAL INTERCESSION CITY P 12-14**		89,349,744	11,878,673	(7,309,549)	-	93,918,868
255							
256	**RIO PINAR**						
257	341 Structures and Improvements	3.2	115,079	-	-	-	115,079
258	342 Fuel Holders, Products, and Accessories	4.0	341,789	-	-	-	341,789
259	343 Prime Movers	2.3	2,142,489	-	-	-	2,142,489
260	344 Generators	2.3	430,677	-	-	-	430,677

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
261	345 Accessory Electric Equipment	4.2	507,055	-	-	-	507,055
262	346 Misc. Power Plant Equipment	8.6	32,379	-	-	-	32,379
263							
264	**TOTAL RIO PINAR**		3,569,470	-	-	-	3,569,470
265							
266	**SUWANNEE**						
267	341 Structures and Improvements	1.3	1,471,200	-	-	-	1,471,200
268	342 Fuel Holders, Products, and Accessories	3.3	3,967,471	2,099,001	-	-	6,066,473
269	343 Prime Movers	1.3	18,934,991	2,045,110	(1,135,654)	-	19,844,447
270	344 Generators	1.4	5,021,099	-	-	-	5,021,099
271	345 Accessory Electric Equipment	1.8	2,131,414	-	-	-	2,131,414
272	346 Misc. Power Plant Equipment	3.2	164,348	-	-	-	164,348
273							
274	**TOTAL SUWANNEE**		31,690,523	4,144,111	(1,135,654)	-	34,698,980
275							
276	SYSTEM ASSETS 346.0	1.5	425,112	87,785	-	-	512,897
277	SYSTEM ASSETS 346.2 (5 YEAR)	20.0	27,945	-	-	-	27,945
278							
279	**TOTAL SYSTEM**		453,057	87,785	-	-	540,842
280							
281	**TIGER BAY**						
282	341 Structures and Improvements	1.7	10,500,517	47,260	(17,706)	-	10,530,071
283	342 Fuel Holders, Products, and Accessories	1.8	2,940,626	33,786	-	-	2,974,411
284	343 Prime Movers	1.4	47,953,365	1,018,935	(3,210,615)	-	45,761,685
285	344 Generators	1.8	11,019,663	1,763,005	(2,458,424)	-	10,324,244
286	345 Accessory Electric Equipment	2.1	5,342,304	(283,185)	-	-	5,059,119
287	346 Misc. Power Plant Equipment	1.4	1,598,099	18,484	(11,598)	-	1,604,986
288	346.2 Misc. Power Plant Equipment (5 Year)	20.0	42,730	-	-	-	42,730
289							
290	**TOTAL TIGER BAY**		79,397,304	2,598,284	(5,698,343)	-	76,297,245
291							
292	**TURNER**						
293	341 Structures and Improvements	2.0	1,539,699	52,039	-	-	1,591,738
294	342 Fuel Holders, Products, and Accessories	3.0	4,632,120	-	-	-	4,632,120
295	343 Prime Movers	1.2	14,141,463	1,308	-	-	14,142,771
296	344 Generators	2.4	4,957,425	65	-	-	4,957,491
297	345 Accessory Electric Equipment	3.0	2,423,999	-	(2,247)	-	2,421,752
298	346 Misc. Power Plant Equipment	2.1	258,903	1,384	-	-	260,287
299	346.2 Misc. Power Plant Equipment (5 Year)	20.0	27,401	-	-	-	27,401
300							
301	**TOTAL TURNER**		27,981,010	54,796	(2,247)	-	28,033,559
302							
303	**UNIVERSITY OF FLORIDA**						
304	341 Structures and Improvements	1.8	6,553,271	-	-	-	6,553,271
305	342 Fuel Holders, Products, and Accessories	2.1	5,957,846	63,905	(5,908)	-	6,015,843

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
306	343 Prime Movers	2.5	20,005,519	1,366,579	(219,825)	(169,951)	20,982,323
307	344 Generators	1.8	3,561,068	-	-	-	3,561,068
308	345 Accessory Electric Equipment	1.9	5,547,691	-	-	-	5,547,691
309	346 Misc. Power Plant Equipment	1.5	1,000,295	-	-	-	1,000,295
310	346.2 Misc. Power Plant Equipment (5 Year)	20.0	14,628	-	-	-	14,628
311	346.3 Misc. Power Plant Equipment (7 Year)	14.3	30,523	-	-	-	30,523
312							
313	**TOTAL UNIVERSITY OF FLORIDA**		42,670,841	1,430,484	(225,733)	(169,951)	43,705,642
314							
315	**TOTAL OTHER PRODUCTION**		2,406,718,195	115,129,775	(89,459,238)	(169,951)	2,432,218,781
316							
317	**TRANSMISSION PLANT**						
318							
319	350.1 TRANSMISSION EASEMENTS	1.2	47,950,625	850,177	-	-	48,800,802
320	352 STRUCTURES	1.4	32,156,330	1,250,088	1,017	(151,635)	33,255,800
321	353.1 STATION EQUIPMENT	1.8	651,547,724	52,490,905	(4,823,973)	(1,028,322)	698,186,334
322	353.2 ENERGY CONTROL CENTER	1.1	36,744,796	833,933	(15,638)	-	37,563,091
323	354 TOWERS AND FIXTURES	1.3	66,260,759	276,347	(17,070)	-	66,520,036
324	355 POLES AND FIXTURES	3.3	551,063,016	36,943,122	(3,108,431)	-	584,897,706
325	356 OVERHEAD CONDUCTOR	1.9	354,931,302	40,541,638	(2,910,067)	-	392,562,874
326	357 UNDERGROUND CONDUIT	1.2	32,127,093	3,503	-	-	32,130,596
327	358 UNDERGROUND CONDUCTOR	2.0	73,053,758	-	-	-	73,053,758
328	359 MISCELLANEOUS PLANT EQUIP.	0.9	3,133,471	-	-	-	3,133,471
329							
330	**TOTAL TRANSMISSION PLANT**		1,848,968,874	133,189,713	(10,874,161)	(1,179,957)	1,970,104,469
331							

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
332	**DISTRIBUTION PLANT**						
333	360.1 DISTRIBUTION EASEMENTS	1.4	556,471	-	-	-	556,471
334	361 STRUCTURES	1.4	26,724,913	1,180,183	(6,111)	30,398	27,929,383
335	362 STATION EQUIPMENT	1.8	552,827,005	29,368,411	(3,442,546)	1,162,905	579,915,775
336	362.2 STATION EQUIPMENT	1.8	71,558	96,617	-	-	168,175
337	364 POLES AND FIXTURES	4.2	527,683,989	25,283,233	(794,488)	-	552,172,734
338	365 OVERHEAD CONDUCTOR	2.7	600,778,569	22,222,355	(6,670,730)	-	616,330,194
339	366 UNDERGROUND CONDUIT	1.6	237,706,742	12,828,547	(317,530)	-	250,217,759
340	367 UNDERGROUND CONDUCTOR	3.0	549,483,044	26,861,425	(4,576,708)	-	571,767,761
341	368 LINE TRANSFORMER	2.9	543,073,058	18,891,584	(8,215,767)	(1)	553,748,875
342	369.1 OVERHEAD SERVICES	1.1	74,915,721	(199,740)	511,554	-	75,227,535
343	369.2 UNDERGROUND SERVICES	2.2	423,555,613	8,242,932	(2,742,559)	-	429,055,986
344	370 METERS	6.0	124,929,931	2,553,962	(245)	(13,346)	127,470,302
345	371 INSTALL ON CUST. PREM.	3.6	3,038,858	(46,881)	77,831	-	3,069,807
346	373 STREET LIGHTING	3.1	306,633,848	10,044,538	(2,040,668)	-	314,637,718
347							
348	**TOTAL DISTRIBUTION PLANT**		3,971,979,320	157,327,167	(28,217,968)	1,179,957	4,102,268,475
349							
350	**GENERAL PLANT**						
351	390 STRUCTURES	3.7	114,152,917	6,173,112	(443,636)	417,284	120,299,677
352	391.1 OFFICE EQUIPMENT	14.3	14,881,403	48,185	(3,092,833)	(253,450)	11,583,304
353	391.2 OFFICE EQUIPMENT	14.3	256,371	-	-	-	256,371
354	391.3 COMPUTERS	14.3	5,927,410	2,471,851	(249,217)	-	8,150,044
355	391.5 DUPLICATING EQUIPMENT	14.3	164,631	-	-	-	164,631
356	393.1 MOTORIZED HANDLING EQUIP.	14.3	794,888	3,290	(83,183)	-	714,995
357	393.2 STORAGE EQUIPMENT	14.3	337,790	5,588	(10,009)	-	333,369
358	393.3 PORTABLE HANDLING EQUIP.	14.3	1,684,689	103,533	-	-	1,788,222
359	394 TOOLS, SHOP & GARAGE EQUIP.	14.3	3,293,877	1,054,551	(331,151)	-	4,017,277
360	394.1 TOOLS, SHOP & GARAGE EQUIP.	14.3	8,070,226	38,948	(6,186,872)	-	1,922,301
361	394.2 TOOLS, SHOP & GARAGE EQUIP.	14.3	5,354,725	(217,755)	(600,744)	-	4,536,225
362	395.0 LABORATORY EQUIPMENT	14.3	165,204	-	-	-	165,204
363	395.2 PORTABLE LABORATORY EQUIP.	14.3	523,432	8	(62,895)	-	460,545
364	396 POWER OPERATED EQUIPMENT	5.8	4,710,480	979,184	(5,763)	-	5,683,901
365	397 COMMUNICATIONS EQUIPMENT	14.3	22,779,478	5,823,971	(3,263,948)	-	25,339,501
366	397.1 COMMUNICATIONS EQUIPMENT	14.3	29,311,140	231,723	(22,782,901)	-	6,759,962
367	398.2 MISCELLANEOUS EQUIPMENT	14.3	9,033,165	(1,567,916)	(657,826)	-	6,807,424
368	399.1 GENERAL PLT ARO		1,974,238	-	-	-	1,974,238
369							
370	**TOTAL GENERAL PLANT**		223,416,063	15,148,273	(37,770,978)	163,834	200,957,191
371							

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101 AND ACCOUNT 106
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DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
TRANSPORTATION EQUIPMENT						
392.1 PASSENGER CARS	8.7	175,747	-	(19,831)	-	155,916
392.2 LIGHT TRUCKS	8.7	24,808,314	924,617	(3,429,707)	-	22,303,224
392.3 HEAVY TRUCKS	4.8	13,010,134	9,488,371	(1,651,469)	-	20,847,036
392.4 SPECIAL EQUIPMENT	5.0	67,357,538	421,598	(6,929,162)	-	60,849,974
392.5 TRAILERS	1.7	11,446,429	(815,112)	(440,258)	-	10,191,059
TOTAL TRANSPORTATION EQUIPMENT		116,798,161	10,019,475	(12,470,427)	-	114,347,209
TOTAL ELECTRIC PLANT		12,656,769,223	513,441,491	(222,788,904)	(4,734,915)	12,942,686,895
ENERGY CONSERVATION EQUIPMENT						
398.1 MISCELLANEOUS	20.0	1,587,734	338,209	(108,122)	-	1,817,821
SUBTOTAL		1,587,734	338,209	(108,122)	-	1,817,821
302 INTANGIBLE PLANT	3.3	8,450,028	-	-	-	8,450,028
303 INTANGIBLE PLANT - CUST SERV SYS	20.0	130,846,355	14,572,958	-	-	145,419,313
SUBTOTAL		139,296,383	14,572,958	-	-	153,869,341
342.9-343.9 GAS CONVERSION	20.0	2,531,240	-	-	-	2,531,240
TOTAL ACCOUNT 111 and 119		143,415,356	14,911,167	(108,122)	-	158,218,401
TOTAL:		**12,800,184,580**	**528,352,658**	**(222,897,026)**	**(4,734,915)**	**13,100,905,296**

NOTE 1: Certain balances for 2010 have been reclassified to conform to the 2011 presentation.

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
1	**STEAM PRODUCTION**						
2	**ANCLOTE**						
3	311 STRUCTURES & IMPROVEMENTS	1.9	37,356,425	628,765	(342,925)	-	37,642,265
4	312 BOILER PLANT EQUIPMENT	2.2	104,507,856	1,635,292	(605,394)	-	105,537,755
5	314 TURBOGENERATOR UNITS	2.8	90,665,983	3,173,296	159,478	-	93,998,757
6	315 ACCESSORY ELECTRIC EQUIPMENT	1.6	26,281,668	605,609	(542,638)	-	26,344,639
7	316.1 MISC POWER PLANT EQUIPMENT	1.7	6,837,392	555,562	233,082	-	7,626,036
8	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	121,812	-	(171,684)	-	(49,873)
9	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	325,699	2,371	(208,660)	-	119,410
10	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		507,681	-	-	-	507,681
11							
12	**TOTAL ANCLOTE**		266,604,516	6,600,894	(1,478,741)	-	271,726,669
13							
14	**BARTOW**						
15	311 STRUCTURES & IMPROVEMENTS		-	-	-	-	-
16	312 BOILER PLANT EQUIPMENT		-	-	-	-	-
17	314 TURBOGENERATOR UNITS		-	-	-	-	-
18	315 ACCESSORY ELECTRIC EQUIPMENT		-	-	-	-	-
19	316 MISC POWER PLANT EQUIPMENT		-	-	-	-	-
20	316 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-
21	316 MISC POWER PLANT EQUIPMENT (7 YEAR)		-	-	-	-	-
22	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		2,610,937	-	-	-	2,610,937
23							
24	**TOTAL BARTOW**		2,610,937	-	-	-	2,610,937
25							
26	**BARTOW-ANCLOTE PIPELINE**						
27	311 STRUCTURES & IMPROVEMENTS	1.8	1,107,226	24,851	-	-	1,132,077
28	312 BOILER PLANT EQUIPMENT	2.6	17,208,791	305	(1,564)	-	17,207,532
29	315 ACCESSORY ELECTRIC EQUIPMENT	1.4	1,165,749	-	-	-	1,165,749
30	316.1 MISC POWER PLANT EQUIPMENT	3.4	147,781	-	-	-	147,781
30	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	8,731	-	-	-	8,731
31							
32	**TOTAL BARTOW-ANCLOTE PIPELINE**		19,638,278	25,156	(1,564)	-	19,661,869
33							
34	**CRYSTAL RIVER 1&2**						
35	311 STRUCTURES & IMPROVEMENTS	2.2	72,744,043	1,072,572	(191,362)	-	73,625,253
36	312 BOILER PLANT EQUIPMENT	3.7	175,557,155	22,113,501	(3,053,235)	-	194,617,422
37	314 TURBOGENERATOR UNITS	2.5	121,620,912	4,916,675	(2,016,264)	-	124,521,323
38	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	34,921,538	1,199,154	87,226	-	36,207,918
39	316.1 MISC POWER PLANT EQUIPMENT	2.1	6,775,031	914,632	(270,538)	-	7,419,125
40	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	(20,350)	-	171,684	-	151,334
41	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	(9,729)	10,577	208,660	-	209,509
42	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		4,923,474	-	-	-	4,923,474
43							
44	**TOTAL CRYSTAL RIVER 1&2**		416,512,073	30,227,112	(5,063,828)	-	441,675,358

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
45							
46	**CRYSTAL RIVER 4&5**						
47	311 STRUCTURES & IMPROVEMENTS	1.5	164,075,116	33,377,431	(382,506)	-	197,070,041
48	312 BOILER PLANT EQUIPMENT	2.5	446,777,139	117,015,865	(11,542,348)	-	552,250,656
49	314 TURBOGENERATOR UNITS	1.0	167,151,842	101,445,958	(5,171,187)	-	263,426,614
50	315 ACCESSORY ELECTRIC EQUIPMENT	1.0	80,118,206	4,649,626	(96,823)	-	84,671,009
51	316.1 MISC POWER PLANT EQUIPMENT	2.1	12,198,787	1,420,575	(18,830)	-	13,600,532
52	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	233,211	-	-	-	233,211
53	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	665,951	-	-	-	665,951
54	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
55							
56	**TOTAL CRYSTAL RIVER 4&5**		871,220,252	257,909,456	(17,211,694)	-	1,111,918,014
57							
58	**SUWANNEE**						
59	311 STRUCTURES & IMPROVEMENTS	2.3	5,091,674	128,973	(32,701)	-	5,187,945
60	312 BOILER PLANT EQUIPMENT	3.1	15,684,386	303,071	(11,113)	-	15,976,344
61	314 TURBOGENERATOR UNITS	2.9	12,631,424	57,600	(29,991)	-	12,659,033
62	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	2,641,805	55,309	-	-	2,697,114
63	316.1 MISC POWER PLANT EQUIPMENT	2.9	600,485	34,072	-	-	634,557
64	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	7,170	-	-	-	7,170
65	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	19,874	-	-	-	19,874
66	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		1,726,484	-	-	-	1,726,484
67							
68	**TOTAL SUWANNEE**		38,403,302	579,024	(73,805)	-	38,908,521
69							
70	**RAIL CARS**	3.4	32,738,780	-	-	-	32,738,780
71							
72	**CRYSTAL RIVER 1&2 COALPILE**	3.7	996,433	-	-	-	996,433
73							
74	**CRYSTAL RIVER 4&5 COALPILE**	2.5	1,727,433	-	-	-	1,727,433
75							
76	**316.2 SYSTEM ASSETS 316.2 (5 YEAR)**	20.0	600,702	-	-	-	600,702
77	**316.3 SYSTEM ASSETS 316.3 (7 YEAR)**	14.3	424,305	-	-	-	424,305
78							
79	**TOTAL STEAM PRODUCTION**		1,651,477,011	295,341,642	(23,829,631)	-	1,922,989,022
80							
81							

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
82	**NUCLEAR PRODUCTION**						
83	**CRYSTAL RIVER#3**						
84	321 STRUCTURES & IMPROVEMENTS	1.5	223,939,572	3,555,663	(965,090)	416,394	226,946,539
85	322 REACTOR PLANT EQUIPMENT	3.3	277,564,964	5,545,868	(1,506,699)	-	281,604,133
86	323 TURBOGENERATOR UNITS	1.2	90,471,737	49,814	(652,937)	-	89,868,613
87	324 ACCESSORY ELECTRIC EQUIPMENT	1.4	179,129,430	48,270	(3,309,161)	-	175,868,538
88	325.1 MISCELLANEOUS POWER EQUIPMENT	1.7	35,392,361	632,911	(12,031,472)	-	23,993,800
89	325.2 MISCELLANEOUS POWER EQUIPMENT (5 YEAR)	20.0	1,882,299	9,584	-	-	1,891,883
90	325.3 MISCELLANEOUS POWER EQUIPMENT (7 YEAR)	14.3	4,405,293	230,276	-	-	4,635,569
91	326 ASSET RETIREMENT COSTS FOR NUCLEAR PROD PLANT		-	-	-	-	-
92							
93	**TOTAL NUCLEAR**		812,785,655	10,072,387	(18,465,360)	416,394	804,809,076
94							
95	**OTHER PRODUCTION**						
96	**AVON PARK PEAKERS**						
97	341 Structures and Improvements	0.6	405,755	-	-	-	405,755
98	342 Fuel Holders, Products, and Accessories	4.8	625,692	-	-	-	625,692
99	343 Prime Movers	3.0	5,904,305	108,533	(70,119)	-	5,942,719
100	344 Generators	0.1	1,290,550	517,016	-	-	1,807,566
101	345 Accessory Electric Equipment	0.5	1,073,156	62,944	-	-	1,136,100
102	346 Misc. Power Plant Equipment	3.2	71,944	-	-	-	71,944
103	346.2 Misc. Power Plant Equipment (5 Year)	20.0	26,451	-	-	-	26,451
104	346.3 Misc. Power Plant Equipment (7 Year)	14.3					
105							
106	**TOTAL AVON PARK PEAKERS**		9,397,853	688,493	(70,119)	-	10,016,226
107							
108	**BARTOW**						
109	341 Structures and Improvements	1.7	1,073,508	-	-	-	1,073,508
110	342 Fuel Holders, Products, and Accessories	3.0	1,801,352	-	(3,206)	-	1,798,146
111	343 Prime Movers	1.6	14,188,240	25,225	-	-	14,213,465
112	344 Generators	2.1	7,406,777	-	-	-	7,406,777
113	345 Accessory Electric Equipment	1.8	2,177,934	-	-	-	2,177,934
114	346 Misc. Power Plant Equipment	0.4	181,067	-	-	-	181,067
115	346.3 Misc. Power Plant Equipment (7 Year)	14.3	1,240	-	-	-	1,240
116							
117	**TOTAL BARTOW**		26,830,119	25,225	(3,206)	-	26,852,138
118							
119	**BARTOW 4x1**						
120	341 Structures and Improvements	3.3	9,058,136	51,887,503	(71,603)	-	60,874,037
121	342 Fuel Holders, Products, and Accessories	3.2	2,842,018	30,665,197	(77,897)	-	33,429,319
122	343 Prime Movers	3.3	-	444,333,996	(16,103,433)	-	428,230,563
123	344 Generators	3.3	187,485	45,477,326	-	-	45,664,811
124	345 Accessory Electric Equipment	3.3	-	34,377,088	-	-	34,377,088
125	346 Misc. Power Plant Equipment	3.3	860,705	15,914,689	(17,275)	-	16,758,119

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DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
TOTAL BARTOW 4x1		12,948,344	622,655,799	(16,270,208)	-	619,333,936
BAYBORO						
341 Structures and Improvements	1.0	1,692,332	-	-	-	1,692,332
342 Fuel Holders, Products, and Accessories	3.0	1,813,435	-	-	-	1,813,435
343 Prime Movers	2.3	13,902,276	130,741	(329,460)	-	13,703,557
344 Generators	1.4	3,579,059	-	-	-	3,579,059
345 Accessory Electric Equipment	1.8	1,196,827	-	-	-	1,196,827
346 Misc. Power Plant Equipment	1.1	424,630	-	(5,701)	-	418,929
346.2 Misc. Power Plant Equipment (5 Year)	20.0	29,609	-	-	-	29,609
346.3 Misc. Power Plant Equipment (7 Year)	14.3					
TOTAL BAYBORO		22,638,168	130,741	(335,161)	-	22,433,748
DEBARY (NEW)						
341 Structures and Improvements	3.3	4,687,604	-	-	-	4,687,604
342 Fuel Holders, Products, and Accessories	4.0	7,925,116	24,836	(7,806)	-	7,942,146
343 Prime Movers	3.7	60,659,989	606,409	(1,892,003)	-	59,374,394
344 Generators	3.3	18,041,197	356,463	(67,725)	-	18,329,935
345 Accessory Electric Equipment	3.4	4,947,148	241,778	(57,107)	-	5,131,818
346 Misc. Power Plant Equipment	4.2	838,168	-	-	-	838,168
TOTAL DEBARY (NEW)		97,099,221	1,229,486	(2,024,642)	-	96,304,065
DEBARY (OLD)						
341 Structures and Improvements	2.7	4,934,243	28,179	(5,588)	-	4,956,834
342 Fuel Holders, Products, and Accessories	2.6	6,380,311	-	-	-	6,380,311
343 Prime Movers	3.0	26,061,366	2,584,782	(285,436)	-	28,360,712
344 Generators	2.4	9,457,806	-	-	-	9,457,806
345 Accessory Electric Equipment	2.5	5,578,624	33,803	(35,422)	-	5,577,005
346 Misc. Power Plant Equipment	3.3	594,451	162,924	(1,501)	-	755,875
346.2 Misc. Power Plant Equipment (5 Year)	20.0	19,741	-	-	-	19,741
TOTAL DEBARY (OLD)		53,026,542	2,809,689	(327,947)	-	55,508,284
HIGGINS						
341 Structures and Improvements	2.9	754,453	-	-	-	754,453
342 Fuel Holders, Products, and Accessories	5.4	1,542,983	440,065	-	-	1,983,048
343 Prime Movers	2.9	11,071,125	31,498	(51,166)	-	11,051,456
344 Generators	2.9	2,640,150	-	-	-	2,640,150
345 Accessory Electric Equipment	3.2	2,671,421	-	-	-	2,671,421
346 Misc. Power Plant Equipment	4.6	284,880	-	-	-	284,880
346.2 Misc. Power Plant Equipment (5 Year)	20.0	16,437	-	-	-	16,437

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SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 101
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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
171			18,981,449	471,563	(51,166)	-	19,401,846
172	**TOTAL HIGGINS**						
173							
174	**HINES #1**						
175	341 Structures and Improvements	2.9	43,189,482	545,749	(119,357)	-	43,615,874
176	342 Fuel Holders, Products, and Accessories	3.2	16,758,959	(90,725)	-	-	16,668,234
177	343 Prime Movers	3.2	131,027,280	14,379,637	(19,381,686)	-	126,025,230
178	344 Generators	2.9	44,807,805	-	-	-	44,807,805
179	345 Accessory Electric Equipment	3.2	21,905,347	114,232	(212,311)	-	21,807,267
180	346 Misc. Power Plant Equipment	3.1	3,679,307	578,374	-	-	4,257,681
181	346.2 Misc. Power Plant Equipment (5 Year)	20.0	19,148	115,042	-	-	134,190
182							
183	**TOTAL HINES #1**		261,387,327	15,642,308	(19,713,354)	-	257,316,282
184							
185	**HINES #2**						
186	341 Structures and Improvements	3.7	43,896,148	(24,615,710)	(11,468)	-	19,268,969
187	342 Fuel Holders, Products, and Accessories	3.2	12,953,803	-	-	-	12,953,803
188	343 Prime Movers	3.3	103,990,664	12,806,120	(21,087,587)	-	95,709,197
189	344 Generators	2.9	39,325,539	-	(2,955,771)	-	36,369,768
190	345 Accessory Electric Equipment	3.2	17,793,092	-	-	-	17,793,092
191	346 Misc. Power Plant Equipment	3.1	2,670,859	65,015	-	-	2,735,874
192							
193	**TOTAL HINES #2**		220,630,103	(11,744,575)	(24,054,826)	-	184,830,703
194							
195	**HINES #3**						
196	341 Structures and Improvements	3.7	10,184,050	169,479	-	-	10,353,529
197	342 Fuel Holders, Products, and Accessories	3.2	15,083,314	-	-	-	15,083,314
198	343 Prime Movers	3.3	128,111,037	9,590,247	(3,602,406)	-	134,098,877
199	344 Generators	2.9	48,245,664	-	-	-	48,245,664
200	345 Accessory Electric Equipment	3.2	21,457,562	95,855	-	-	21,553,417
201	346 Misc. Power Plant Equipment	3.1	1,483,987	-	-	-	1,483,987
202							
203	**TOTAL HINES #3**		224,565,613	9,855,581	(3,602,406)	-	230,818,788
204							
205	**HINES #4**						
206	341 Structures and Improvements	3.7	11,899,220	52,738	-	-	11,951,959
207	342 Fuel Holders, Products, and Accessories	3.2	7,326,290	10,751	-	-	7,337,041
208	343 Prime Movers	3.3	170,279,371	924,170	(11,941,246)	-	159,262,295
209	344 Generators	2.9	45,038,139	34,086	-	-	45,072,225
210	345 Accessory Electric Equipment	3.2	22,592,398	-	-	-	22,592,398
211	346 Misc. Power Plant Equipment	3.1	7,095,186	102,044	-	-	7,197,230
212							
213	**TOTAL HINES #4**		264,230,603	1,123,790	(11,941,246)	-	253,413,147
214							
215	**INTERCESSION CITY P1-6**						

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
216	341 Structures and Improvements	2.9	3,736,548	-	-	-	3,736,548
217	342 Fuel Holders, Products, and Accessories	6.6	3,308,521	-	-	-	3,308,521
218	343 Prime Movers	2.7	21,637,046	851,763	(1,330,370)	-	21,158,440
219	344 Generators	2.6	4,716,975	-	-	-	4,716,975
220	345 Accessory Electric Equipment	3.1	2,810,060	-	(23,636)	-	2,786,424
221	346 Misc. Power Plant Equipment	5.5	948,191	92,453	(334)	-	1,040,310
222	346.3 Misc. Power Plant Equipment (7 Year)	14.3	1,299	-	-	-	1,299
223							
224	**TOTAL INTERCESSION CITY P 1-6**		37,158,640	944,216	(1,354,340)	-	36,748,516
225							
226	**INTERCESSION CITY (NEW) P7-10**						
227	341 Structures and Improvements	2.5	9,411,083	4,079	(1,188)	-	9,413,974
228	342 Fuel Holders, Products, and Accessories	2.8	7,002,238	-	(8,361)	-	6,993,877
229	343 Prime Movers	2.6	58,169,282	44,770	(4,183,614)	-	54,030,438
230	344 Generators	2.5	17,338,871	112,274	-	-	17,451,145
231	345 Accessory Electric Equipment	2.5	5,166,362	2,554	(576)	-	5,168,341
232	346 Misc. Power Plant Equipment	2.3	1,036,448	-	-	-	1,036,448
233	346.2 Misc. Power Plant Equipment (5 Year)	20.0	48,968	-	-	-	48,968
234							
235	**TOTAL INTERCESSION CITY P 7-10**		98,173,252	163,677	(4,193,739)	-	94,143,190
236							
237	**INTERCESSION CITY P11**						
238	341 Structures and Improvements	4.0	1,240,693	-	(2,402)	-	1,238,290
239	342 Fuel Holders, Products, and Accessories	4.4	1,379,318	-	-	-	1,379,318
240	343 Prime Movers	4.6	13,806,598	30,195	-	-	13,836,793
241	344 Generators	4.0	2,664,079	-	-	-	2,664,079
242	345 Accessory Electric Equipment	4.0	3,619,321	-	(132,464)	-	3,486,857
243	346 Misc. Power Plant Equipment	3.8	188,206	-	-	-	188,206
244							
245	**TOTAL INTERCESSION CITY P 11**		22,898,214	30,195	(134,866)	-	22,793,543
246							
247	**INTERCESSION CITY P12-14**						
248	341 Structures and Improvements	2.8	1,426,366	-	(11,673)	-	1,414,693
249	342 Fuel Holders, Products, and Accessories	3.0	4,212,640	10,794	(3,796)	-	4,219,638
250	343 Prime Movers	2.9	56,250,686	3,601,646	(7,294,080)	-	52,558,252
251	344 Generators	2.5	16,681,378	-	-	-	16,681,378
252	345 Accessory Electric Equipment	2.6	6,886,452	-	-	-	6,886,452
253							
254	**TOTAL INTERCESSION CITY P 12-14**		85,457,523	3,612,439	(7,309,549)	-	81,760,413
255							
256	**RIO PINAR**						
257	341 Structures and Improvements	3.2	115,079	-	-	-	115,079
258	342 Fuel Holders, Products, and Accessories	4.0	341,789	-	-	-	341,789
259	343 Prime Movers	2.3	2,142,489	-	-	-	2,142,489
260	344 Generators	2.3	430,677	-	-	-	430,677

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345 Accessory Electric Equipment	4.2	503,254	3,801	-	-	507,055
346 Misc. Power Plant Equipment	8.6	22,906	9,473	-	-	32,379
TOTAL RIO PINAR		3,556,195	13,274	-	-	3,569,470
SUWANNEE						
341 Structures and Improvements	1.3	1,471,200	-	-	-	1,471,200
342 Fuel Holders, Products, and Accessories	3.3	3,967,471	-	-	-	3,967,471
343 Prime Movers	1.3	18,503,992	430,999	(1,135,654)	-	17,799,338
344 Generators	1.4	5,021,099	-	-	-	5,021,099
345 Accessory Electric Equipment	1.8	2,082,354	49,060	-	-	2,131,414
346 Misc. Power Plant Equipment	3.2	152,238	2,625	-	-	154,863
TOTAL SUWANNEE		31,198,354	482,684	(1,135,654)	-	30,545,385
SYSTEM ASSETS 346.0	1.5	406,307	87,785	-	-	494,092
SYSTEM ASSETS 346.2 (5 YEAR)	20.0	27,945	-	-	-	27,945
TOTAL SYSTEM		434,252	87,785	-	-	522,037
TIGER BAY						
341 Structures and Improvements	1.7	10,393,475	-	(17,706)	-	10,375,769
342 Fuel Holders, Products, and Accessories	1.8	2,974,411	-	-	-	2,974,411
343 Prime Movers	1.4	19,739,725	19,088	(3,210,615)	-	16,548,198
344 Generators	1.8	11,019,663	-	(2,458,424)	-	8,561,239
345 Accessory Electric Equipment	2.1	5,304,549	-	-	-	5,304,549
346 Misc. Power Plant Equipment	1.4	1,591,393	-	(11,598)	-	1,579,796
346.2 Misc. Power Plant Equipment (5 Year)	20.0	42,730	-	-	-	42,730
TOTAL TIGER BAY		51,065,946	19,088	(5,698,343)	-	45,386,691
TURNER						
341 Structures and Improvements	2.0	1,321,648	184,220	-	-	1,505,868
342 Fuel Holders, Products, and Accessories	3.0	2,582,472	-	-	-	2,582,472
343 Prime Movers	1.2	10,518,036	181,254	-	-	10,699,290
344 Generators	2.4	3,837,181	-	-	-	3,837,181
345 Accessory Electric Equipment	3.0	2,355,628	-	(2,247)	-	2,353,381
346 Misc. Power Plant Equipment	2.1	241,274	19,013	-	-	260,287
346.2 Misc. Power Plant Equipment (5 Year)	20.0	27,401	-	-	-	27,401
TOTAL TURNER		20,883,640	384,487	(2,247)	-	21,265,880
UNIVERSITY OF FLORIDA						
341 Structures and Improvements	1.8	6,503,869	-	-	-	6,503,869
342 Fuel Holders, Products, and Accessories	2.1	5,491,841	67,826	(5,908)	-	5,553,759

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
306	343 Prime Movers	2.5	17,219,355	2,582,737	(219,825)	-	19,582,267
307	344 Generators	1.8	3,561,068	-	-	-	3,561,068
308	345 Accessory Electric Equipment	1.9	5,125,583	422,107	-	-	5,547,691
309	346 Misc. Power Plant Equipment	1.5	995,623	4,672	-	-	1,000,295
310	346.2 Misc. Power Plant Equipment (5 Year)	20.0	14,628	-	-	-	14,628
311	346.3 Misc. Power Plant Equipment (7 Year)	14.3	30,523	-	-	-	30,523
312							
313	**TOTAL UNIVERSITY OF FLORIDA**		38,942,490	3,077,343	(225,733)	-	41,794,100
314							
315	**TOTAL OTHER PRODUCTION**		1,601,503,850	651,703,288	(98,448,752)	-	2,154,758,386
316							
317	**TRANSMISSION PLANT**						
318							
319	350.1 TRANSMISSION EASEMENTS	1.2	47,941,615	859,187	-	-	48,800,802
320	352 STRUCTURES	1.4	23,215,393	765,295	1,017	(30,398)	23,951,307
321	353.1 STATION EQUIPMENT	1.8	508,320,430	96,132,472	(4,655,330)	316,875	600,114,446
322	353.2 ENERGY CONTROL CENTER	1.1	33,402,753	897,669	(15,638)	-	34,284,784
323	354 TOWERS AND FIXTURES	1.3	66,086,353	1,291	(17,070)	-	66,070,574
324	355 POLES AND FIXTURES	3.3	362,225,188	125,962,140	(3,108,431)	78,486	485,157,383
325	356 OVERHEAD CONDUCTOR	1.9	256,564,821	81,372,307	(2,910,067)	-	335,027,062
326	357 UNDERGROUND CONDUIT	1.2	32,124,261	6,334	-	-	32,130,596
327	358 UNDERGROUND CONDUCTOR	2.0	73,041,080	-	-	-	73,041,080
328	359 MISCELLANEOUS PLANT EQUIP.	0.9	3,133,471	-	-	-	3,133,471
329							
330	**TOTAL TRANSMISSION PLANT**		1,406,055,364	305,996,695	(10,705,518)	364,963	1,701,711,504
331							

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DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
DISTRIBUTION PLANT						
360.1 DISTRIBUTION EASEMENTS	1.4	556,471	-	-	-	556,471
361 STRUCTURES	1.4	25,010,711	1,100,951	(6,111)	30,398	26,135,949
362 STATION EQUIPMENT	1.8	434,300,150	78,509,924	(3,442,546)	53,931	509,421,459
362.2 STATION EQUIPMENT	1.8	63,898	6,839	-	-	70,737
364 POLES AND FIXTURES	4.2	517,336,910	26,800,436	(782,547)	-	543,354,800
365 OVERHEAD CONDUCTOR	2.7	578,146,105	28,597,197	(6,650,086)	1,331,361	601,424,577
366 UNDERGROUND CONDUIT	1.6	231,697,858	16,449,483	(317,530)	-	247,829,810
367 UNDERGROUND CONDUCTOR	3.0	520,457,803	31,457,047	(4,576,708)	-	547,338,142
368 LINE TRANSFORMER	2.9	499,439,975	(11,067,593)	(8,215,642)	919,179	481,075,920
369.1 OVERHEAD SERVICES	1.1	74,059,976	(199,740)	515,508	-	74,375,745
369.2 UNDERGROUND SERVICES	2.2	415,711,651	12,247,184	(2,742,559)	-	425,216,275
370 METERS	6.0	108,880,843	80,622	(245)	(13,346)	108,947,874
371 INSTALL ON CUST. PREM.	3.6	2,139,299	79,133	77,831	-	2,296,262
373 STREET LIGHTING	3.1	304,580,309	11,280,517	(2,039,998)	-	313,820,828
TOTAL DISTRIBUTION PLANT		3,712,381,957	195,341,999	(28,180,633)	2,321,524	3,881,864,848
GENERAL PLANT						
390 STRUCTURES	3.7	105,885,267	672,274	(443,636)	409,491	106,523,397
391.1 OFFICE EQUIPMENT	14.3	9,913,725	123,851	(3,092,833)	(253,450)	6,691,293
391.2 OFFICE EQUIPMENT	14.3	119,009	-	-	-	119,009
391.3 COMPUTERS	14.3	4,237,807	711,234	(249,217)	-	4,699,823
391.5 DUPLICATING EQUIPMENT	14.3	-	-	-	-	-
393.1 MOTORIZED HANDLING EQUIP.	14.3	791,033	7,145	(83,183)	-	714,995
393.2 STORAGE EQUIPMENT	14.3	245,015	41,641	(10,009)	-	276,646
393.3 PORTABLE HANDLING EQUIP.	14.3	23,773	114,823	-	-	138,597
394 TOOLS, SHOP & GARAGE EQUIP.	14.3	2,346,005	1,803,335	(331,151)	-	3,818,189
394.1 TOOLS, SHOP & GARAGE EQUIP.	14.3	8,008,301	65,050	(6,186,872)	-	1,886,479
394.2 TOOLS, SHOP & GARAGE EQUIP.	14.3	3,610,212	966,199	(600,744)	-	3,975,667
395.0 LABORATORY EQUIPMENT	14.3	143,001	22,203	-	-	165,204
395.2 PORTABLE LABORATORY EQUIP.	14.3	360,211	83,617	(62,895)	-	380,932
396 POWER OPERATED EQUIPMENT	5.8	4,549,899	1,117,946	(5,763)	-	5,662,082
397 COMMUNICATIONS EQUIPMENT	14.3	16,049,591	3,071,634	(3,263,948)	-	15,857,277
397.1 COMMUNICATIONS EQUIPMENT	14.3	28,648,091	179,630	(22,782,901)	-	6,044,820
398.2 MISCELLANEOUS EQUIPMENT	14.3	3,399,550	1,189,349	(657,826)	-	3,931,073
399.1 GENERAL PLT ARO		1,974,238	-	-	-	1,974,238
TOTAL GENERAL PLANT		190,304,729	10,169,932	(37,770,978)	156,041	162,859,724

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
372	**TRANSPORTATION EQUIPMENT**						
373	392.1 PASSENGER CARS	8.7	175,747	-	(19,831)	-	155,916
374	392.2 LIGHT TRUCKS	8.7	18,679,858	6,321,903	(3,429,707)	-	21,572,054
375	392.3 HEAVY TRUCKS	4.8	11,391,538	3,189,375	(1,651,469)	-	12,929,444
376	392.4 SPECIAL EQUIPMENT	5.0	60,889,458	6,461,991	(6,929,162)	-	60,422,287
377	392.5 TRAILERS	1.7	7,520,946	1,774,643	(440,258)	-	8,855,331
378							
379	**TOTAL TRANSPORTATION EQUIPMENT**		98,657,547	17,747,911	(12,470,427)	-	103,935,032
380							
381	**TOTAL ELECTRIC PLANT**		9,473,166,114	1,486,373,855	(229,871,298)	3,258,921	10,732,927,591
382							
383	**ENERGY CONSERVATION EQUIPMENT**						
384	398.1 MISCELLANEOUS	20.0	1,341,492	384,767	(108,122)	-	1,618,137
385							
386	**SUBTOTAL**		1,341,492	384,767	(108,122)	-	1,618,137
387							
388	302 INTANGIBLE PLANT	3.3	8,450,028	-	-	-	8,450,028
389	303 INTANGIBLE PLANT - CUST SERV SYS	20.0	118,797,291	510,844	-	-	119,308,135
390							
391	**SUBTOTAL**		127,247,319	510,844	-	-	127,758,163
392							
393	342.9-343.9 GAS CONVERSION	20.0	2,531,240	-	-	-	2,531,240
394							
395	**TOTAL ACCOUNT 111 and 119**		131,120,052	895,611	(108,122)	-	131,907,540
396							
397	**TOTAL:**		**9,604,286,165**	**1,487,269,466**	**(229,979,420)**	**3,258,921**	**10,864,835,132**
398							
399							
400	**NOTE 1:** Certain balances for 2010 have been reclassified to conform to the 2011 presentation.						
401							

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
1	**STEAM PRODUCTION**						
2	**ANCLOTE**						
3	311 STRUCTURES & IMPROVEMENTS	1.9	814,765	(448,906)	-	-	365,859
4	312 BOILER PLANT EQUIPMENT	2.2	2,099,548	(554,112)	-	-	1,545,436
5	314 TURBOGENERATOR UNITS	2.8	25,225,890	(2,187,117)	-	-	23,038,772
6	315 ACCESSORY ELECTRIC EQUIPMENT	1.6	607,942	(470,175)	-	-	137,767
7	316.1 MISC POWER PLANT EQUIPMENT	1.7	561,094	(253,960)	-	-	307,134
8	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	-	-	-	-	-
9	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	19,501	(2,371)	-	-	17,131
10							
11	**TOTAL ANCLOTE**		29,328,740	(3,916,641)	-	-	25,412,099
12							
13	**BARTOW**						
14	311 STRUCTURES & IMPROVEMENTS		-	-	-	-	-
15	312 BOILER PLANT EQUIPMENT		-	-	-	-	-
16	314 TURBOGENERATOR UNITS		-	-	-	-	-
17	315 ACCESSORY ELECTRIC EQUIPMENT		-	-	-	-	-
18	316 MISC POWER PLANT EQUIPMENT		-	-	-	-	-
19	316 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-
20	316 MISC POWER PLANT EQUIPMENT (7 YEAR)		-	-	-	-	-
21	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
22							
23	**TOTAL BARTOW**		-	-	-	-	-
24							
25	**BARTOW-ANCLOTE PIPELINE**						
26	311 STRUCTURES & IMPROVEMENTS	1.8	58,894	(16,368)	-	-	42,526
27	312 BOILER PLANT EQUIPMENT	2.6	108,662	10,717	-	-	119,379
28	315 ACCESSORY ELECTRIC EQUIPMENT	1.4	909,406	-	-	-	909,406
29	316.1 MISC POWER PLANT EQUIPMENT	3.4	-	135,074	-	-	135,074
29	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	-	-	-	-	-
30							
31	**TOTAL BARTOW-ANCLOTE PIPELINE**		1,076,962	129,423	-	-	1,206,385
32							
33	**CRYSTAL RIVER 1&2**						
34	311 STRUCTURES & IMPROVEMENTS	2.2	3,373,376	(403,462)	-	-	2,969,914
35	312 BOILER PLANT EQUIPMENT	3.7	22,435,150	(17,378,777)	-	(2,510,118)	2,546,256
36	314 TURBOGENERATOR UNITS	2.5	5,600,791	(2,593,829)	-	-	3,006,963
37	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	917,536	315,971	-	92,101	1,325,608
38	316.1 MISC POWER PLANT EQUIPMENT	2.1	1,225,274	(758,148)	-	-	467,126
39	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	-	-	-	-	-
40	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	10,180	(10,180)	-	-	-
41	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
42							
43	**TOTAL CRYSTAL RIVER 1&2**		33,562,307	(20,828,424)	-	(2,418,017)	10,315,866
44							

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
45	**CRYSTAL RIVER 4&5**						
46	311 STRUCTURES & IMPROVEMENTS	1.5	120,455,783	(23,830,252)	-	-	96,625,531
47	312 BOILER PLANT EQUIPMENT	2.5	1,180,349,822	(132,200,313)	(15,461)	(1,500,000)	1,046,634,048
48	314 TURBOGENERATOR UNITS	1.0	85,000,178	(78,313,582)	-	-	6,686,596
49	315 ACCESSORY ELECTRIC EQUIPMENT	1.0	114,210,217	1,037,754	-	-	115,247,970
50	316.1 MISC POWER PLANT EQUIPMENT	2.1	1,471,682	310,709	-	747,203	2,529,593
51	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	-	-	-	-	-
52	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	-	-	-	-	-
53	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
54							
55	**TOTAL CRYSTAL RIVER 4&5**		1,501,487,681	(232,995,684)	(15,461)	(752,797)	1,267,723,739
56							
57	**SUWANNEE**						
58	311 STRUCTURES & IMPROVEMENTS	2.3	164,781	2,382	-	-	167,163
59	312 BOILER PLANT EQUIPMENT	3.1	496,568	(205,602)	-	-	290,966
60	314 TURBOGENERATOR UNITS	2.9	715,014	50,337	-	-	765,352
61	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	119,070	(55,309)	-	-	63,761
62	316.1 MISC POWER PLANT EQUIPMENT	2.9	155,542	10,744	-	-	166,286
63	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	-	-	-	-	-
64	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	-	-	-	-	-
65	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-
66							
67	**TOTAL SUWANNEE**		1,650,976	(197,448)	-	-	1,453,528
68							
69	**RAIL CARS**	3.4	-	-	-	-	-
70							
71	**CRYSTAL RIVER 1&2 COALPILE**	3.7	-	-	-	-	-
72							
73	**CRYSTAL RIVER 4&5 COALPILE**	2.5	1,753,978	(1,753,978)	-	-	-
74							
75	**316.2 SYSTEM ASSETS 316.2 (5 YEAR)**	20.0	-	-	-	-	-
76	**316.3 SYSTEM ASSETS 316.3 (7 YEAR)**	14.3	-	-	-	-	-
77							
78	**TOTAL STEAM PRODUCTION**		1,568,860,645	(259,562,754)	(15,461)	(3,170,814)	1,306,111,616
79							
80							
81	**NUCLEAR PRODUCTION**						
82	**CRYSTAL RIVER#3**						
83	321 STRUCTURES & IMPROVEMENTS	1.5	15,593,619	35,478,967	(240,418)	(1,227,175)	49,604,993
84	322 REACTOR PLANT EQUIPMENT	3.3	21,399,611	(1,916,927)	(1,445,263)	-	18,037,421
85	323 TURBOGENERATOR UNITS	1.2	5,014,549	1,771,375	-	-	6,785,923
86	324 ACCESSORY ELECTRIC EQUIPMENT	1.4	5,435,186	922,914	-	-	6,358,100
87	325.1 MISCELLANEOUS POWER EQUIPMENT	1.7	7,989,583	128,015	-	(747,203)	7,370,395
88	325.2 MISCELLANEOUS POWER EQUIPMENT (5 YEAR)	20.0	7,522	105,228	-	-	112,749

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
89	325.3 MISCELLANEOUS POWER EQUIPMENT (7 YEAR)	14.3	325,231	286,243	-	-	611,474
90	326 ASSET RETIREMENT COSTS FOR NUCLEAR PROD PLANT		-	-	-	-	-
91							
92	**TOTAL NUCLEAR**		55,765,300	36,775,814	(1,685,681)	(1,974,378)	88,881,055
93							
94	**OTHER PRODUCTION**						
95	**AVON PARK PEAKERS**						
96	341 Structures and Improvements	0.6	52,579	1,406	-	-	53,984
97	342 Fuel Holders, Products, and Accessories	4.8	4,828	-	-	-	4,828
98	343 Prime Movers	3.0	84,401	(61,947)	-	-	22,455
99	344 Generators	0.1	517,016	(517,016)	-	-	-
100	345 Accessory Electric Equipment	0.5	94,135	(62,944)	-	-	31,192
101	346 Misc. Power Plant Equipment	3.2	-	-	-	-	-
102	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
103	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
104							
105	**TOTAL AVON PARK PEAKERS**		752,959	(640,501)	-	-	112,459
106							
107	**BARTOW**						
108	341 Structures and Improvements	1.7	2,841	27,552	-	-	30,392
109	342 Fuel Holders, Products, and Accessories	3.0	1,356,076	-	-	-	1,356,076
110	343 Prime Movers	1.6	72,945	263,523	-	-	336,468
111	344 Generators	2.1	33,064	-	-	-	33,064
112	345 Accessory Electric Equipment	1.8	-	-	-	-	-
113	346 Misc. Power Plant Equipment	0.4	9,311	5,116	-	-	14,428
114	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
115							
116	**TOTAL BARTOW**		1,474,236	296,191	-	-	1,770,427
117							
118	**BARTOW 4x1**						
119	341 Structures and Improvements	3.3	50,975,885	(49,927,180)	-	-	1,048,705
120	342 Fuel Holders, Products, and Accessories	3.2	23,318,971	(33,204,257)	9,974,238	-	88,951
121	343 Prime Movers	3.3	450,005,887	(427,583,893)	-	-	22,421,994
122	344 Generators	3.3	49,645,133	(49,645,133)	-	-	-
123	345 Accessory Electric Equipment	3.3	21,991,425	(21,991,425)	-	-	-
124	346 Misc. Power Plant Equipment	3.3	19,798,458	(18,497,990)	-	-	1,300,467
125							-
126	**TOTAL BARTOW 4x1**		615,735,758	(600,849,877)	9,974,238	-	24,860,119
127							
128	**BAYBORO**						
129	341 Structures and Improvements	1.0	-	-	-	-	-
130	342 Fuel Holders, Products, and Accessories	3.0	40,368	21,904	-	-	62,271
131	343 Prime Movers	2.3	2,438,263	934,328	-	-	3,372,592
132	344 Generators	1.4	-	-	-	-	-
133	345 Accessory Electric Equipment	1.8	-	-	-	-	-

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
134	346 Misc. Power Plant Equipment	1.1	-	10,184	-	-	10,184
135	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
136	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
137							
138	**TOTAL BAYBORO**		2,478,631	966,416	-	-	3,445,047
139							
140	**DEBARY (NEW)**						
141	341 Structures and Improvements	3.3	-	-	-	-	-
142	342 Fuel Holders, Products, and Accessories	4.0	41,765	(16,739)	-	-	25,026
143	343 Prime Movers	3.7	4,898,977	1,089,141	-	-	5,988,118
144	344 Generators	3.3	334,548	(225,061)	-	-	109,487
145	345 Accessory Electric Equipment	3.4	194,203	(102,469)	-	-	91,735
146	346 Misc. Power Plant Equipment	4.2	-	49,449	-	-	49,449
147							
148	**TOTAL DEBARY (NEW)**		5,469,493	794,321	-	-	6,263,814
149							
150	**DEBARY (OLD)**						
151	341 Structures and Improvements	2.7	73,977	(10,466)	-	-	63,511
152	342 Fuel Holders, Products, and Accessories	2.6	2,520,883	1,210,622	-	-	3,731,505
153	343 Prime Movers	3.0	2,275,745	(1,553,914)	-	-	721,831
154	344 Generators	2.4	-	-	-	-	-
155	345 Accessory Electric Equipment	2.5	239,927	(3,086)	-	-	236,841
156	346 Misc. Power Plant Equipment	3.3	265,643	(139,210)	-	-	126,433
157	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
158							
159	**TOTAL DEBARY (OLD)**		5,376,175	(496,054)	-	-	4,880,121
160							
161	**HIGGINS**						
162	341 Structures and Improvements	2.9	-	-	-	-	-
163	342 Fuel Holders, Products, and Accessories	5.4	440,065	(440,065)	-	-	-
164	343 Prime Movers	2.9	-	44,422	-	-	44,422
165	344 Generators	2.9	-	-	-	-	-
166	345 Accessory Electric Equipment	3.2	-	-	-	-	-
167	346 Misc. Power Plant Equipment	4.6	-	-	-	-	-
168	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
169							
170			440,065	(395,643)	-	-	44,422
171	**TOTAL HIGGINS**						
172							

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
173	**HINES #1**						
174	341 Structures and Improvements	2.9	2,378,341	(200,641)	-	-	2,177,700
175	342 Fuel Holders, Products, and Accessories	3.2	114,260	(114,260)	-	-	-
176	343 Prime Movers	3.2	59,653,081	10,397,312	(984,724)	-	69,065,669
177	344 Generators	2.9	-	-	-	-	-
178	345 Accessory Electric Equipment	3.2	316,661	194,394	-	-	511,054
179	346 Misc. Power Plant Equipment	3.1	557,782	(290,361)	-	-	267,421
180	346.2 Misc. Power Plant Equipment (5 Year)	20.0	198,654	(157,403)	-	-	41,251
181							
182	**TOTAL HINES #1**		63,218,778	9,829,041	(984,724)	-	72,063,095
183							
184	**HINES #2**						
185	341 Structures and Improvements	3.7	2,866,944	(2,842,544)	-	-	24,400
186	342 Fuel Holders, Products, and Accessories	3.2	-	-	-	-	-
187	343 Prime Movers	3.3	21,231,544	13,521,942	-	-	34,753,486
188	344 Generators	2.9	-	3,204,933	-	-	3,204,933
189	345 Accessory Electric Equipment	3.2	-	8,931	-	-	8,931
190	346 Misc. Power Plant Equipment	3.1	65,015	(65,015)	-	-	-
191							
192	**TOTAL HINES #2**		24,163,503	13,828,247	-	-	37,991,750
193							
194	**HINES #3**						
195	341 Structures and Improvements	3.7	82,009	(82,009)	-	-	-
196	342 Fuel Holders, Products, and Accessories	3.2	36,572	-	-	-	36,572
197	343 Prime Movers	3.3	16,621,590	3,417,915	-	-	20,039,504
198	344 Generators	2.9	2,828,848	449,578	-	-	3,278,426
199	345 Accessory Electric Equipment	3.2	95,925	(95,925)	-	-	(0)
200	346 Misc. Power Plant Equipment	3.1	-	-	-	-	-
201							
202	**TOTAL HINES #3**		19,664,944	3,689,559	-	-	23,354,502
203							
204	**HINES #4**						
205	341 Structures and Improvements	3.7	52,056	(52,056)	-	-	-
206	342 Fuel Holders, Products, and Accessories	3.2	10,751	27,734	-	-	38,485
207	343 Prime Movers	3.3	13,230,738	16,188,903	-	-	29,419,641
208	344 Generators	2.9	34,086	(34,086)	-	-	-
209	345 Accessory Electric Equipment	3.2	-	21,306	-	-	21,306
210	346 Misc. Power Plant Equipment	3.1	102,044	(102,044)	-	-	-
211							
212	**TOTAL HINES #4**		13,429,676	16,049,757	-	-	29,479,432
213							
214	**INTERCESSION CITY P1-6**						
215	341 Structures and Improvements	2.9	56,036	9,962	-	-	65,998
216	342 Fuel Holders, Products, and Accessories	6.6	451,521	-	-	-	451,521

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
217	343 Prime Movers	2.7	2,264,503	2,242,025	-	-	4,506,527
218	344 Generators	2.6	-	-	-	-	-
219	345 Accessory Electric Equipment	3.1	692,173	13,391	-	-	705,564
220	346 Misc. Power Plant Equipment	5.5	206,352	(105,717)	-	-	100,635
221	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
222							
223	**TOTAL INTERCESSION CITY P 1-6**		3,670,585	2,159,661	-	-	5,830,245
224							
225	**INTERCESSION CITY (NEW) P7-10**						
226	341 Structures and Improvements	2.5	4,079	3,796	-	-	7,875
227	342 Fuel Holders, Products, and Accessories	2.8	83,936	14,623	-	-	98,559
228	343 Prime Movers	2.6	4,932,101	5,657,224	-	-	10,589,325
229	344 Generators	2.5	409,668	(112,274)	-	-	297,394
230	345 Accessory Electric Equipment	2.5	52,992	-	-	-	52,992
231	346 Misc. Power Plant Equipment	2.3	-	5,818	-	-	5,818
232	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
233							
234	**TOTAL INTERCESSION CITY P 7-10**		5,482,776	5,569,186	-	-	11,051,962
235							
236	**INTERCESSION CITY P11**						
237	341 Structures and Improvements	4.0	20,726	2,626	-	-	23,352
238	342 Fuel Holders, Products, and Accessories	4.4	-	-	-	-	-
239	343 Prime Movers	4.6	262,492	(30,195)	-	-	232,297
240	344 Generators	4.0	-	-	-	-	-
241	345 Accessory Electric Equipment	4.0	-	136,720	-	-	136,720
242	346 Misc. Power Plant Equipment	3.8	-	-	-	-	-
243							
244	**TOTAL INTERCESSION CITY P 11**		283,218	109,150	-	-	392,368
245							
246	**INTERCESSION CITY P12-14**						
247	341 Structures and Improvements	2.8	-	19,823	-	-	19,823
248	342 Fuel Holders, Products, and Accessories	3.0	47,019	7,097	-	-	54,116
249	343 Prime Movers	2.9	3,845,202	8,239,314	-	-	12,084,516
250	344 Generators	2.5	-	-	-	-	-
251	345 Accessory Electric Equipment	2.6	-	-	-	-	-
252							
253	**TOTAL INTERCESSION CITY P 12-14**		3,892,222	8,266,234	-	-	12,158,455
254							
255	**RIO PINAR**						
256	341 Structures and Improvements	3.2	-	-	-	-	-
257	342 Fuel Holders, Products, and Accessories	4.0	-	-	-	-	-
258	343 Prime Movers	2.3	-	-	-	-	-
259	344 Generators	2.3	-	-	-	-	-
260	345 Accessory Electric Equipment	4.2	3,801	(3,801)	-	-	-

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
261	346 Misc. Power Plant Equipment	8.6	9,473	(9,473)	-	-	-
262							
263	**TOTAL RIO PINAR**		13,274	(13,274)	-	-	-
264							
265	**SUWANNEE**						
266	341 Structures and Improvements	1.3	-	-	-	-	-
267	342 Fuel Holders, Products, and Accessories	3.3	-	2,099,001	-	-	2,099,001
268	343 Prime Movers	1.3	430,999	1,614,110	-	-	2,045,110
269	344 Generators	1.4	-	-	-	-	-
270	345 Accessory Electric Equipment	1.8	49,060	(49,060)	-	-	-
271	346 Misc. Power Plant Equipment	3.2	12,110	(2,625)	-	-	9,485
272							
273	**TOTAL SUWANNEE**		492,169	3,661,427	-	-	4,153,596
274							
275	SYSTEM ASSETS 346.0	1.5	18,805	-	-	-	18,805
276	SYSTEM ASSETS 346.2 (5 YEAR)	20.0	-	-	-	-	-
277							
278	**TOTAL SYSTEM**		18,805	-	-	-	18,805
279							
280	**TIGER BAY**						
281	341 Structures and Improvements	1.7	107,042	47,260	-	-	154,301
282	342 Fuel Holders, Products, and Accessories	1.8	(33,786)	33,786	-	-	-
283	343 Prime Movers	1.4	28,213,640	999,847	-	-	29,213,488
284	344 Generators	1.8	-	1,763,005	-	-	1,763,005
285	345 Accessory Electric Equipment	2.1	37,755	(283,185)	-	-	(245,430)
286	346 Misc. Power Plant Equipment	1.4	6,706	18,484	-	-	25,190
287	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
288							
289	**TOTAL TIGER BAY**		28,331,357	2,579,196	-	-	30,910,554
290							
291	**TURNER**						
292	341 Structures and Improvements	2.0	218,051	(132,182)	-	-	85,869
293	342 Fuel Holders, Products, and Accessories	3.0	2,049,648	-	-	-	2,049,648
294	343 Prime Movers	1.2	3,623,426	(179,946)	-	-	3,443,480
295	344 Generators	2.4	1,120,245	65	-	-	1,120,310
296	345 Accessory Electric Equipment	3.0	68,371	-	-	-	68,371
297	346 Misc. Power Plant Equipment	2.1	17,629	(17,629)	-	-	-
298	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
299							
300	**TOTAL TURNER**		7,097,370	(329,691)	-	-	6,767,679
301							
302	**UNIVERSITY OF FLORIDA**						
303	341 Structures and Improvements	1.8	49,401	-	-	-	49,401
304	342 Fuel Holders, Products, and Accessories	2.1	466,006	(3,921)	-	-	462,085
305	343 Prime Movers	2.5	2,786,165	(1,216,158)	-	(169,951)	1,400,056

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	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
306	344 Generators	1.8	-	-	-	-	-
307	345 Accessory Electric Equipment	1.9	422,107	(422,107)	-	-	-
308	346 Misc. Power Plant Equipment	1.5	4,672	(4,672)	-	-	-
309	346.2 Misc. Power Plant Equipment (5 Year)	20.0	-	-	-	-	-
310	346.3 Misc. Power Plant Equipment (7 Year)	14.3	-	-	-	-	-
311							
312	**TOTAL UNIVERSITY OF FLORIDA**		3,728,351	(1,646,858)	-	(169,951)	1,911,542
313							
314	**TOTAL OTHER PRODUCTION**		805,214,345	(536,573,513)	8,989,514	(169,951)	277,460,395
315							
316	**TRANSMISSION PLANT**						
317							
318	350.1 TRANSMISSION EASEMENTS	1.2	9,010	(9,010)	-	-	-
319	352 STRUCTURES	1.4	8,940,937	484,793	-	(121,237)	9,304,493
320	353.1 STATION EQUIPMENT	1.8	143,227,294	(43,641,567)	(168,643)	(1,345,197)	98,071,888
321	353.2 ENERGY CONTROL CENTER	1.1	3,342,044	(63,736)	-	-	3,278,308
322	354 TOWERS AND FIXTURES	1.3	174,406	275,056	-	-	449,462
323	355 POLES AND FIXTURES	3.3	188,837,828	(89,019,018)	-	(78,486)	99,740,323
324	356 OVERHEAD CONDUCTOR	1.9	98,366,481	(40,830,669)	-	-	57,535,812
325	357 UNDERGROUND CONDUIT	1.2	2,831	(2,831)	-	-	-
326	358 UNDERGROUND CONDUCTOR	2.0	12,679	-	-	-	12,679
327	359 MISCELLANEOUS PLANT EQUIP.	0.9	-	-	-	-	-
328							
329	**TOTAL TRANSMISSION PLANT**		442,913,510	(172,806,983)	(168,643)	(1,544,920)	268,392,965
330							
331	**DISTRIBUTION PLANT**						
332	360.1 DISTRIBUTION EASEMENTS	1.4	-	-	-	-	-
333	361 STRUCTURES	1.4	1,714,202	79,233	-	-	1,793,435
334	362 STATION EQUIPMENT	1.8	118,526,855	(49,141,514)	-	1,108,974	70,494,316
335	362.2 STATION EQUIPMENT	1.8	7,660	89,778	-	-	97,438
336	364 POLES AND FIXTURES	4.2	10,347,079	(1,517,203)	(11,941)	-	8,817,934
337	365 OVERHEAD CONDUCTOR	2.7	22,632,465	(6,374,842)	(20,644)	(1,331,361)	14,905,617
338	366 UNDERGROUND CONDUIT	1.6	6,008,885	(3,620,936)	-	-	2,387,949
339	367 UNDERGROUND CONDUCTOR	3.0	29,025,241	(4,595,622)	-	-	24,429,619
340	368 LINE TRANSFORMER	2.9	43,633,083	29,959,177	(125)	(919,180)	72,672,955
341	369.1 OVERHEAD SERVICES	1.1	855,745	-	(3,954)	-	851,791
342	369.2 UNDERGROUND SERVICES	2.2	7,843,962	(4,004,251)	-	-	3,839,711
343	370 METERS	6.0	16,049,088	2,473,340	-	-	18,522,428
344	371 INSTALL ON CUST. PREM.	3.6	899,559	(126,014)	-	-	773,545
345	373 STREET LIGHTING	3.1	2,053,539	(1,235,978)	(671)	-	816,890
346							
347	**TOTAL DISTRIBUTION PLANT**		259,597,362	(38,014,832)	(37,335)	(1,141,567)	220,403,628
348							
349	**GENERAL PLANT**						

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
350	390 STRUCTURES	3.7	8,267,650	5,500,837	-	7,793	13,776,280
351	391.1 OFFICE EQUIPMENT	14.3	4,967,677	(75,666)	-	-	4,892,011
352	391.2 OFFICE EQUIPMENT	14.3	137,362	-	-	-	137,362
353	391.3 COMPUTERS	14.3	1,689,604	1,760,617	-	-	3,450,220
354	391.5 DUPLICATING EQUIPMENT	14.3	164,631	-	-	-	164,631
355	393.1 MOTORIZED HANDLING EQUIP.	14.3	3,855	(3,855)	-	-	-
356	393.2 STORAGE EQUIPMENT	14.3	92,775	(36,052)	-	-	56,722
357	393.3 PORTABLE HANDLING EQUIP.	14.3	1,660,916	(11,291)	-	-	1,649,625
358	394 TOOLS, SHOP & GARAGE EQUIP.	14.3	947,872	(748,784)	-	-	199,088
359	394.1 TOOLS, SHOP & GARAGE EQUIP.	14.3	61,925	(26,103)	-	-	35,822
360	394.2 TOOLS, SHOP & GARAGE EQUIP.	14.3	1,744,513	(1,183,954)	-	-	560,558
361	395.0 LABORATORY EQUIPMENT	14.3	22,203	(22,203)	-	-	-
362	395.2 PORTABLE LABORATORY EQUIP.	14.3	163,221	(83,609)	-	-	79,612
363	396 POWER OPERATED EQUIPMENT	5.8	160,581	(138,762)	-	-	21,819
364	397 COMMUNICATIONS EQUIPMENT	14.3	6,729,886	2,752,337	-	-	9,482,224
365	397.1 COMMUNICATIONS EQUIPMENT	14.3	663,049	52,093	-	-	715,142
366	398.2 MISCELLANEOUS EQUIPMENT	14.3	5,633,615	(2,757,265)	-	-	2,876,350
367	399.1 GENERAL PLT ARO		-	-	-	-	-
368							
369	**TOTAL GENERAL PLANT**		33,111,334	4,978,340	-	7,793	38,097,467
370							
371	**TRANSPORTATION EQUIPMENT**						
372	392.1 PASSENGER CARS	8.7	-	-	-	-	-
373	392.2 LIGHT TRUCKS	8.7	6,128,455	(5,397,286)	-	-	731,170
374	392.3 HEAVY TRUCKS	4.8	1,618,596	6,298,997	-	-	7,917,592
375	392.4 SPECIAL EQUIPMENT	5.0	6,468,079	(6,040,393)	-	-	427,687
376	392.5 TRAILERS	1.7	3,925,483	(2,589,755)	-	-	1,335,728
377							
378	**TOTAL TRANSPORTATION EQUIPMENT**		18,140,614	(7,728,437)	-	-	10,412,177
379							
380	**TOTAL ELECTRIC PLANT**		3,183,603,110	(972,932,364)	7,082,394	(7,993,836)	2,209,759,303
381							
382	**ENERGY CONSERVATION EQUIPMENT**						
383	398.1 MISCELLANEOUS	20.0	246,241	(46,558)	-	-	199,684
384							
385	**SUBTOTAL**		246,241	(46,558)	-	-	199,684
386							
387	302 INTANGIBLE PLANT	3.3	-	-	-	-	-
388	303 INTANGIBLE PLANT - CUST SERV SYS	20.0	12,049,063	14,062,114	-	-	26,111,177
389							
390	**SUBTOTAL**		12,049,063	14,062,114	-	-	26,111,177
391							
392	342.9-343.9 GAS CONVERSION	20.0	-	-	-	-	-
393							

PROGRESS ENERGY FLORIDA
SUMMARY OF PLANT TRANSACTIONS - ACCOUNT 106
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	BALANCE 12/31/2010 (NOTE 1)	ADDITIONS	RETIREMENTS	TRANSFERS & ADJUSTMENTS	BALANCE 12/31/2011
394	**TOTAL ACCOUNT 111 and 119**		12,295,305	14,015,556	-	-	26,310,861
395							
396	**TOTAL:**		**3,195,898,415**	**(958,916,808)**	**7,082,394**	**(7,993,836)**	**2,236,070,164**
397							
398							
399	**NOTE 1:** Certain balances for 2010 have been reclassified to conform to the 2011 presentation.						
400							

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - ACCOUNT 108
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
1	STEAM PRODUCTION								
2	ANCLOTE								
3	311 STRUCTURES & IMPROVEMENTS	1.9	27,934,164	(160,533)	(38,162)	-	-	715,547	28,451,015
4	312 BOILER PLANT EQUIPMENT	2.2	71,422,557	(689,766)	(89,324)	304,586	-	2,318,784	73,266,838
5	314 TURBOGENERATOR UNITS	2.8	64,162,396	(169,825)	(3,698,130)	267,889	3,289,944	3,248,508	67,100,782
6	315 ACCESSORY ELECTRIC EQUIPMENT	1.6	20,020,837	(64,868)	(27,672)	6,123	-	424,114	20,358,535
7	316.1 MISC POWER PLANT EQUIPMENT	1.7	4,775,336	(34,872)	(6,136)	-	-	122,939	4,857,267
8	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	121,812	-	-	-	-	-	121,812
9	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	345,583	-	-	-	-	-	345,583
10	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		(642,559)	-	-	-	-	(10,913)	(653,473)
11									
12	TOTAL ANCLOTE		188,140,126	(1,119,865)	(3,859,424)	578,598	3,289,944	6,818,979	193,848,359
13									
14	BARTOW								
15	311 STRUCTURES & IMPROVEMENTS		6,334,198	-	(3,151,915)	-	2,362,500	-	5,544,783
16	312 BOILER PLANT EQUIPMENT		5,016,098	-	102,261	-	(2,862,810)	-	2,255,549
17	314 TURBOGENERATOR UNITS		407,674	-	(4,289)	-	-	-	403,385
18	315 ACCESSORY ELECTRIC EQUIPMENT		342,888	-	-	-	-	-	342,888
19	316 MISC POWER PLANT EQUIPMENT		15,276	-	-	-	-	-	15,276
20	316 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-	-	-
21	316 MISC POWER PLANT EQUIPMENT (7 YEAR)		(55,700)	-	-	-	-	-	(55,700)
22	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		(17,463)	-	(1,276,819)	-	1,340,842	-	46,560
23									
24	TOTAL BARTOW		12,042,972		(4,330,763)	-	840,532	-	8,552,741
25									
26	CRYSTAL RIVER 1&2								
27	311 STRUCTURES & IMPROVEMENTS	2.2	59,867,134	(373,753)	(71,036)	4,812	-	1,652,888	61,080,044
28	312 BOILER PLANT EQUIPMENT	3.7	130,051,734	(2,968,862)	(1,777,235)	1,164,535	-	7,344,992	133,815,165
29	314 TURBOGENERATOR UNITS	2.5	95,020,962	(1,686,961)	(346,544)	343,695	-	3,246,808	96,577,960
30	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	28,081,645	(390,544)	(89,130)	-	-	927,411	28,529,383
31	316.1 MISC POWER PLANT EQUIPMENT	2.1	5,227,243	(2,584)	(39,134)	9,210	-	156,739	5,351,475
32	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	151,334	-	-	-	-	-	151,334
33	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	237,787	-	-	-	-	39,959	277,745
34	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		(6,415,417)	-	-	-	-	73,079	(6,342,339)
35									
36	TOTAL CRYSTAL RIVER 1&2		312,222,422	(5,422,704)	(2,323,079)	1,522,252	-	13,441,874	319,440,767
37									
38	CRYSTAL RIVER 4&5								
39	311 STRUCTURES & IMPROVEMENTS	1.5	94,980,067	(382,506)	(129,592)	-	-	4,269,790	98,737,759
40	312 BOILER PLANT EQUIPMENT	2.5	357,601,246	(11,557,809)	(5,647,377)	735,261	-	39,398,970	380,530,290
41	314 TURBOGENERATOR UNITS	1.0	124,635,932	(5,171,187)	(3,911,167)	3,408,422	-	2,502,395	121,464,395
42	315 ACCESSORY ELECTRIC EQUIPMENT	1.0	59,197,059	(96,823)	(47,466)	-	-	1,867,943	60,920,713
43	316.1 MISC POWER PLANT EQUIPMENT	2.1	8,468,341	(18,830)	(17,217)	7,747	49,056	298,093	8,787,189
44	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	233,211	-	-	-	-	-	233,211
45	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	665,940	-	-	-	-	-	665,940
46	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-	-	-
47									
48	TOTAL CRYSTAL RIVER 4&5		645,781,797	(17,227,155)	(9,752,820)	4,151,429	49,056	48,337,191	671,339,498
49									
50	SUWANNEE								

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - ACCOUNT 108
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
51	311 STRUCTURES & IMPROVEMENTS	2.3	4,915,022	(32,701)	(4,148)	-	-	94,682	4,972,854
52	312 BOILER PLANT EQUIPMENT	3.1	14,960,804	(11,113)	(53,879)	-	-	503,261	15,399,073
53	314 TURBOGENERATOR UNITS	2.9	13,016,305	(29,991)	(182,967)	-	-	362,659	13,166,007
54	315 ACCESSORY ELECTRIC EQUIPMENT	2.6	2,545,364	-	(37,843)	-	-	71,783	2,579,304
55	316.1 MISC POWER PLANT EQUIPMENT	2.9	488,894	-	-	-	(4,215)	26,557	511,236
56	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)	20.0	7,170	-	-	-	-	-	7,170
57	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)	14.3	-	-	-	-	-	-	-
58	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		(4,033,322)	-	-	-	-	(103,850)	(4,137,172)
59									
60	**TOTAL SUWANNEE**		31,900,236	(73,805)	(278,836)	-	(4,215)	955,092	32,498,472
61									
62	**HIGGINS**								
63	311 STRUCTURES & IMPROVEMENTS		1,463,256	-	-	-	(1,463,256)	-	-
64	312 BOILER PLANT EQUIPMENT		-	-	-	-	-	-	-
65	314 TURBOGENERATOR UNITS		-	-	-	-	-	-	-
66	315 ACCESSORY ELECTRIC EQUIPMENT		-	-	-	-	-	-	-
67	316.1 MISC POWER PLANT EQUIPMENT		-	-	-	-	-	-	-
68	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-	-	-
69	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)		-	-	-	-	-	-	-
70	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-	-	-
71									
72	**TOTAL HIGGINS**		1,463,256	-	-	-	(1,463,256)	-	-
73									
74	**TURNER**								
75	311 STRUCTURES & IMPROVEMENTS		1,734,085	-	-	-	(1,734,085)	-	-
76	312 BOILER PLANT EQUIPMENT		-	-	-	-	-	-	-
77	314 TURBOGENERATOR UNITS		-	-	-	-	-	-	-
78	315 ACCESSORY ELECTRIC EQUIPMENT		-	-	-	-	-	-	-
79	316.1 MISC POWER PLANT EQUIPMENT		-	-	-	-	-	-	-
80	316.2 MISC POWER PLANT EQUIPMENT (5 YEAR)		-	-	-	-	-	-	-
81	316.3 MISC POWER PLANT EQUIPMENT (7 YEAR)		-	-	-	-	-	-	-
82	317 ASSET RETIREMENT COSTS FOR STEAM PROD PLANT		-	-	-	-	-	-	-
83									
84	**TOTAL TURNER**		1,734,085	-	-	-	(1,734,085)	-	-
85									
86	**BARTOW-ANCLOTE PIPELINE**								
87	311 STRUCTURES & IMPROVEMENTS	1.8	693,527	-	242	-	-	21,252	715,021
88	312 BOILER PLANT EQUIPMENT	2.6	11,450,394	(1,564)		-	-	443,075	11,891,906
89	315 ACCESSORY ELECTRIC EQUIPMENT	1.4	988,371	-	-	-	-	28,129	1,016,500
90	316.3 MISC POWER PLANT EQUIPMENT	14.3	78,931	-	-	-	-	5,154	84,085
91									
92	**TOTAL BARTOW-ANCLOTE PIPELINE**		13,211,223	(1,564)	242	-	-	497,610	13,707,511
93									
94	**RAIL CARS**	3.4	31,114,019	-	-	-	-	642,597	31,756,617
95									
96	**CRYSTAL RIVER 1&2 COALPILE**	3.7	1,120,402	-	-	-	-	(8,109)	1,112,293
97									
98	**CRYSTAL RIVER 4&5 COALPILE**	2.5	7,551,135	-	-	-	-	(2,812)	7,548,323
99									
100	**316.2 SYSTEM ASSETS 316.2 (5 YEAR)**	20.0	600,702	-	-	-	-	-	600,702

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - ACCOUNT 108
DECEMBER 31, 2011

	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
101	**316.3 SYSTEM ASSETS 316.3 (7 YEAR)**	14.3	413,712	-	-	-	-	-	413,712
102								-	
103	**Steam Retirement work in process**		(45,868,812)	-	(246,834)	(2,570,714)	-	-	(48,686,360)
104									
105	**TOTAL STEAM PRODUCTION**		1,201,427,276	(23,845,092)	(20,791,513)	3,681,566	977,976	70,682,422	1,232,132,635
106									
107	**FOSSIL DISMANTLEMENT - STEAM**								
108	ANCLOTE		10,776,361	-	-	-	-	232,936	11,009,297
109	AVON PARK		-	-	-	-	-	-	-
110	BARTOW		24,069,123	-	6,190,995	-	(2,464,167)	-	27,795,951
111	BARTOW-ANCLOTE PIPELINE		7,440,853	-	-	-	-	574,928	8,015,782
112	CRYSTAL RIVER 1&2		52,046,508	-	-	-	-	1,342,891	53,389,399
113	CRYSTAL RIVER 4&5		20,409,854	-	-	-	-	627,398	21,037,252
114	HIGGINS		-	-	-	-	(45,195)	-	(45,195)
115	INGLIS		-	-	-	-	-	-	-
116	SUWANNEE		16,677,669	-	-	-	-	216,593	16,894,262
117	TURNER		25,915	-	-	-	(47,408)	-	(21,494)
118									
119	**SUBTOTAL**		131,446,282	-	6,190,995	-	(2,556,770)	2,994,747	138,075,255
120									
121	**FOSSIL DISMANTLEMENT - OTHER PROD.**								
122	AVON PARK		184,519	-	-	-	-	3,485	188,005
123	BARTOW CC		(86,886)	-	-	-	-	(7,753)	(94,639)
124	BARTOW CT		334,320	-	-	-	(3,151,915)	7,222	(2,810,373)
125	BAYBORO PEAK		1,079,394	-	-	-	-	21,329	1,100,723
126	DEBARY(OLD)		521,773	-	-	-	-	13,601	535,374
127	DEBARY (NEW)		4,688,509	-	-	-	-	396,844	5,085,353
128	HIGGINS PEAK		363,642	-	-	-	-	7,077	370,719
129	HINES UNIT 1		157,748	-	-	-	-	21,228	178,975
130	HINES UNIT 2		61,341	-	-	-	-	17,650	78,991
131	HINES UNIT 3		20,388	-	-	-	-	16,643	37,031
132	HINES UNIT 4		26,676	-	-	-	-	19,989	46,664
133	INTERCESSION CITY 1-6		457,326	-	-	-	-	10,363	467,688
134	INTERCESSION CITY SIEMENS 11		89,076	-	-	-	-	12,516	101,592
135	INTERCESSION CITY 7-10 (NEW)		1,466,250	-	-	-	-	59,188	1,525,437
136	INTERCESSION CITY P12-14		1,626,871	-	-	-	-	207,479	1,834,350
137	PORT ST. JOE		-	-	-	-	-	-	-
138	RIO PINAR		352,385	-	-	-	-	6,930	359,315
139	SUWANNEE		259,368	-	-	-	-	6,992	266,360
140	TIGER BAY		102,442	-	-	-	-	10,912	113,354
141	TURNER		471,548	-	-	-	-	9,751	481,299
142	UNIVERSITY OF FLORIDA		181,951	-	-	-	-	9,028	190,979
143									
144	**SUBTOTAL**		12,358,640	-	-	-	(3,151,915)	850,473	10,057,198
145									
146	TOTAL FOSSIL DISMANTLEMENT		143,804,922	-	6,190,995	-	(5,708,686)	3,845,220	148,132,452
147									
148	**NUCLEAR PRODUCTION**								
149	**CRYSTAL RIVER#3**								

DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
321 STRUCTURES & IMPROVEMENTS	1.5	147,059,605	(1,205,508)	(425,307)	-	-	3,538,222	148,967,012
322 REACTOR PLANT EQUIPMENT	3.3	196,044,440	(2,951,962)	(1,193,032)	23,720	-	9,874,127	201,797,294
323 TURBOGENERATOR UNITS	1.2	76,082,039	(652,937)	(3,409)	29,850	-	1,151,217	76,606,760
324 ACCESSORY ELECTRIC EQUIPMENT	1.4	127,193,647	(3,309,161)	-	-	-	2,604,509	126,488,995
325.1 MISCELLANEOUS POWER EQUIPMENT	1.7	15,170,501	(12,031,472)			(49,056)	707,519	3,797,492
325.2 MISCELLANEOUS POWER EQUIPMENT (5 YEAR)	20.0	1,888,625	-	-	-	-	34,534	1,923,158
325.3 MISCELLANEOUS POWER EQUIPMENT (7 YEAR)	14.3	4,560,298	-	-	-	-	459,175	5,019,473
326 ASSET RETIREMENT COSTS FOR NUCLEAR PROD PLANT		24,231	-	-	-	740,621	(764,851)	-
Nuclear Retirement work in process		(34,366,935)	-	(10,452,197)	375,084	-	-	(44,444,047)
TOTAL		533,656,451	(20,151,040)	(12,073,944)	428,654	691,565	17,604,450	520,156,136
DECOMMISSIONING - RETAIL		57,812,196	-	-	-	1,683,357	-	59,495,553
DECOMMISSIONING - WHOLESALE		3,773,076				(1,683,357)		2,089,719
TOTAL		61,585,272	-	-	-	-	-	61,585,272
TOTAL NUCLEAR		595,241,724	(20,151,040)	(12,073,944)	428,654	691,565	17,604,450	581,741,408
OTHER PRODUCTION								
AVON PARK PEAKERS								
341 Structures and Improvements	0.6	291,816	-	-	-	-	2,935	294,751
342 Fuel Holders, Products, and Accessories	4.8	568,408	-	-	-	-	30,265	598,673
343 Prime Movers	3.0	5,042,586	(70,119)	(48,781)	17,748	-	178,981	5,120,416
344 Generators	0.1	1,301,418	-	(516,041)	-	-	9,078	794,454
345 Accessory Electric Equipment	0.5	1,054,542	-	(32,542)	-	-	5,416	1,027,416
346 Misc. Power Plant Equipment	3.2	30,957	-	-	-	-	2,302	33,260
346.2 Misc. Power Plant Equipment	20.0	29,179	-	-	-	-	-	29,179
TOTAL AVON PARK PEAKERS		8,318,905	(70,119)	(597,363)	17,748	-	228,977	7,898,148
BARTOW								
341 Structures and Improvements	1.7	543,569	-	-	-	-	18,250	561,819
342 Fuel Holders, Products, and Accessories	3.0	1,266,802	(3,206)	-	-	-	94,703	1,358,298
343 Prime Movers	1.6	11,026,911	-	-	-	-	223,893	11,250,804
344 Generators	2.1	5,091,532	-	-	-	-	156,237	5,247,769
345 Accessory Electric Equipment	1.8	1,482,157	-	-	-	-	39,074	1,521,231
346 Misc. Power Plant Equipment	0.4	301,702	(17,275)	(113)	-	-	134,884	419,199
346.2 Misc. Power Plant Equipment (5 Year)	20.0	1,411	-	-	-	-	-	1,411
TOTAL BARTOW		19,714,084	(20,481)	(113)	-	-	667,041	20,360,531
BARTOW 4x1								
341 Structures and Improvements	3.3	4,199,865	9,902,635	-	-	-	1,986,300	16,088,800
342 Fuel Holders, Products, and Accessories	3.2	4,855,301	(77,897)	-	-	-	1,062,634	5,840,037
343 Prime Movers	3.3	24,358,690	(16,103,433)	-	-	-	14,829,528	23,084,785
344 Generators	3.3	2,847,737	-	-	-	-	1,527,934	4,375,671
345 Accessory Electric Equipment	3.3	1,188,649	-	-	-	-	1,128,689	2,317,338
346 Misc. Power Plant Equipment	3.3	1,028,778	-	-	-	-	75,198	1,103,976

PROGRESS ENERGY FLORIDA
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	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
200	**TOTAL BARTOW 4x1**		38,479,020	(6,278,695)	-	-	-	20,610,282	52,810,607
201									
202	**BAYBORO**								
203	341 Structures and Improvements	1.0	1,126,130	-	-	-	-	17,333	1,143,463
204	342 Fuel Holders, Products, and Accessories	3.0	944,920	-	-	-	-	55,632	1,000,553
205	343 Prime Movers	2.3	8,516,901	(329,460)	(13,138)	-	-	383,840	8,558,142
206	344 Generators	1.4	2,480,923	-	-	-	-	50,336	2,531,259
207	345 Accessory Electric Equipment	1.8	754,107	-	-	-	-	22,042	776,149
208	346 Misc. Power Plant Equipment	1.1	299,472	(5,701)	-	-	-	4,806	298,577
209	346.2 Misc. Power Plant Equipment (5 Year)	20.0	31,021	-	-	-	-	-	31,021
210									
211	**TOTAL BAYBORO**		14,153,474	(335,161)	(13,138)	-	-	533,988	14,339,163
212									
213	**DEBARY (NEW)**								
214	341 Structures and Improvements	3.3	2,276,304	-	-	-	-	154,691	2,430,995
215	342 Fuel Holders, Products, and Accessories	4.0	5,047,363	(2,838)	(297)	-	-	277,548	5,321,777
216	343 Prime Movers	3.7	35,373,398	(1,892,003)	(170,226)	6,950	-	2,430,448	35,748,566
217	344 Generators	3.3	10,634,174	(67,725)	(28,316)	-	-	607,292	11,145,425
218	345 Accessory Electric Equipment	3.4	2,880,577	(57,107)	(2,793)	109,076	-	176,669	3,106,422
219	346 Misc. Power Plant Equipment	4.2	385,584	-	-	-	-	35,386	420,970
220									
221	**TOTAL DEBARY (NEW)**		56,597,401	(2,019,674)	(201,632)	116,026	-	3,682,034	58,174,156
222									
223	**DEBARY (OLD)**								
224	341 Structures and Improvements	2.7	3,130,289	(5,588)	(7,350)	-	-	135,339	3,252,690
225	342 Fuel Holders, Products, and Accessories	2.6	5,333,546	-	-	-	-	232,743	5,566,288
226	343 Prime Movers	3.0	19,930,900	(285,436)	(421,641)	1,746,243	-	860,784	21,830,849
227	344 Generators	2.4	7,352,059	-	-	-	-	226,987	7,579,046
228	345 Accessory Electric Equipment	2.5	4,537,622	(35,422)	(340)	28,598	-	145,380	4,675,839
229	346 Misc. Power Plant Equipment	3.3	380,803	(1,501)	(171)	140	-	28,758	408,029
230	346.2 Misc. Power Plant Equipment (5 Year)	20.0	21,576						21,576
231									
232	**TOTAL DEBARY (OLD)**		40,686,794	(327,947)	(429,502)	1,774,982	-	1,629,989	43,334,317
233									
234	**HIGGINS**								
235	341 Structures and Improvements	2.9	567,433	-	-	-	-	21,879	589,312
236	342 Fuel Holders, Products, and Accessories	5.4	1,411,012	-	-	-	-	107,085	1,518,096
237	343 Prime Movers	2.9	8,393,107	(51,166)	(3,657)	-	-	321,399	8,659,683
238	344 Generators	2.9	2,313,733	-	-	-	-	66,004	2,379,737
239	345 Accessory Electric Equipment	3.2	2,093,157	-	-	-	-	88,157	2,181,313
240	346 Misc. Power Plant Equipment	4.6	87,420	-	-	-	-	13,104	100,524
241	346.2 Misc. Power Plant Equipment (5 Year)	20.0	18,109	-	-	-	-	-	18,109
242									
243			14,883,970	(51,166)	(3,657)	-	-	617,628	15,446,775
244	**TOTAL HIGGINS**								
245									
246	**HINES #1**								
247	341 Structures and Improvements	2.9	14,764,000	(119,357)	(9,062)	-	-	1,325,473	15,961,054
248	342 Fuel Holders, Products, and Accessories	3.2	7,846,180	-	(51,964)	-	-	533,383	8,327,599
249	343 Prime Movers	3.2	38,328,109	(20,366,410)	(1,631,116)	8,272,844	-	6,171,156	30,774,582

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	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
250	344 Generators	2.9	16,327,942	-	-	-	-	1,299,426	17,627,369
251	345 Accessory Electric Equipment	3.2	7,506,299	(212,311)	-	-	-	712,339	8,006,327
252	346 Misc. Power Plant Equipment	3.1	1,145,991	-	(2,347)	-	-	136,394	1,280,038
253	346.2 Misc. Power Plant Equipment (5 Year)	20.0	120,377	-	-	-	-	39,677	160,054
254									
255	**TOTAL HINES #1**		86,038,898	(20,698,078)	(1,694,490)	8,272,844	-	10,217,849	82,137,022
256									
257	**HINES #2**								
258	341 Structures and Improvements	3.7	10,482,376	(11,468)	-	-	-	790,324	11,261,232
259	342 Fuel Holders, Products, and Accessories	3.2	3,469,332	-	-	-	-	414,522	3,883,854
260	343 Prime Movers	3.3	5,777,389	(21,087,587)	(484,881)	9,173,717	-	4,264,101	(2,357,261)
261	344 Generators	2.9	9,623,078	(2,955,771)	-	-	-	1,138,247	7,805,554
262	345 Accessory Electric Equipment	3.2	3,672,227	-	-	-	-	569,581	4,241,808
263	346 Misc. Power Plant Equipment	3.1	544,988	-	-	-	-	84,812	629,800
264									
265	**TOTAL HINES #2**		33,569,390	(24,054,826)	(484,881)	9,173,717	-	7,261,587	25,464,987
266									
267	**HINES #3**								
268	341 Structures and Improvements	3.7	2,893,223	-	-	-	-	300,142	3,193,364
269	342 Fuel Holders, Products, and Accessories	3.2	7,999,315	-	-	-	-	483,836	8,483,152
270	343 Prime Movers	3.3	18,810,673	(3,602,406)	(593,889)	7,012,046	-	5,036,110	26,662,534
271	344 Generators	2.9	14,505,836	-	-	-	-	1,481,839	15,987,675
272	345 Accessory Electric Equipment	3.2	6,529,771	-	(367)	-	-	689,710	7,219,114
273	346 Misc. Power Plant Equipment	3.1	361,137	-	-	-	-	46,004	407,140
274									-
275	**TOTAL HINES #3**		51,099,955	(3,602,406)	(594,256)	7,012,046	-	8,037,640	61,952,979
276									
277	**HINES #4**								
278	341 Structures and Improvements	3.7	2,908,993	-	-	-	-	346,601	3,255,594
279	342 Fuel Holders, Products, and Accessories	3.2	1,247,572	-	-	-	-	234,933	1,482,505
280	343 Prime Movers	3.3	20,095,209	(11,941,246)	(8,538)	1,073,577	-	6,035,154	15,254,156
281	344 Generators	2.9	1,169,875	-	-	-	-	1,307,094	2,476,969
282	345 Accessory Electric Equipment	3.2	2,887,590	-	-	-	-	723,383	3,610,973
283	346 Misc. Power Plant Equipment	3.1	330,567	-	-	-	-	223,143	553,709
284									
285	**TOTAL HINES #4**		28,639,805	(11,941,246)	(8,538)	1,073,577	-	8,870,308	26,633,906
286									
287	**INTERCESSION CITY P1-6**								
288	341 Structures and Improvements	2.9	2,459,625	-	-	-	-	110,057	2,569,683
289	342 Fuel Holders, Products, and Accessories	6.6	2,979,877	-	-	-	-	248,163	3,228,040
290	343 Prime Movers	2.7	16,010,407	(1,330,370)	(68,649)	232,861	-	652,371	15,496,621
291	344 Generators	2.6	3,565,549	-	-	-	-	122,641	3,688,191
292	345 Accessory Electric Equipment	3.1	2,254,545	(23,636)	-	-	-	108,556	2,339,465
293	346 Misc. Power Plant Equipment	5.5	430,770	(334)	-	-	-	62,774	493,211
294									
295	**TOTAL INTERCESSION CITY P 1-6**		27,700,774	(1,354,340)	(68,649)	232,861	-	1,304,562	27,815,210
296									
297	**INTERCESSION CITY (NEW) P7-10**								
298	341 Structures and Improvements	2.5	4,220,046	(1,188)	(1,113)	-	-	239,342	4,457,088
299	342 Fuel Holders, Products, and Accessories	2.8	3,386,938	(8,361)	-	-	-	200,580	3,579,157

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DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
343 Prime Movers	2.6	27,617,189	(4,183,614)	(34,590)	4,000	-	1,626,223	25,029,209
344 Generators	2.5	8,309,933	-	(22,632)	-	-	451,665	8,738,966
345 Accessory Electric Equipment	2.5	2,498,936	(576)	-	-	-	132,768	2,631,128
346 Misc. Power Plant Equipment	2.3	516,800	-	-	-	-	23,499	540,299
346.2 Misc. Power Plant Equipment (5 Year)	20.0	50,326	-	-	-	-	-	50,326
TOTAL INTERCESSION CITY P 7-10		46,600,168	(4,193,739)	(58,334)	4,000	-	2,674,077	45,026,172
INTERCESSION CITY P11								
341 Structures and Improvements	4.0	595,619	(2,402)	-	-	-	50,444	643,660
342 Fuel Holders, Products, and Accessories	4.4	791,131	-	-	-	-	60,690	851,821
343 Prime Movers	4.6	6,582,661	-	(28,170)	17,976	-	649,429	7,221,897
344 Generators	4.0	1,467,478	-	-	-	-	106,563	1,574,041
345 Accessory Electric Equipment	4.0	2,042,211	(132,464)	-	-	-	144,780	2,054,527
346 Misc. Power Plant Equipment	3.8	108,048	-	-	-	-	7,125	115,173
TOTAL INTERCESSION CITY P 11		11,587,147	(134,866)	(28,170)	17,976	-	1,019,030	12,461,118
INTERCESSION CITY P12-14								
341 Structures and Improvements	2.8	64,605	(11,673)	-	-	-	39,966	92,898
342 Fuel Holders, Products, and Accessories	3.0	39,602	(3,796)	(57,655)	-	-	127,993	106,145
343 Prime Movers	2.9	14,799,272	(7,294,080)	(129,166)	3,275,993	-	1,793,602	12,445,621
344 Generators	2.5	6,627,372	-	-	-	-	418,236	7,045,607
345 Accessory Electric Equipment	2.6	2,570,591	-	-	-	-	179,929	2,750,520
346 Misc. Power Plant Equipment		-	-	-	-	-	-	-
TOTAL INTERCESSION CITY P 12-14		24,101,442	(7,309,549)	(186,821)	3,275,993	-	2,559,725	22,440,791
RIO PINAR								
341 Structures and Improvements	3.2	70,010	-	(134)	-	-	3,691	73,567
342 Fuel Holders, Products, and Accessories	4.0	369,497	-	-	-	-	(3,224)	366,274
343 Prime Movers	2.3	1,918,676	-	-	-	-	50,081	1,968,756
344 Generators	2.3	381,968	-	-	-	-	9,906	391,873
345 Accessory Electric Equipment	4.2	390,415	-	(1,435)	-	-	21,296	410,276
346 Misc. Power Plant Equipment	8.6	13,870	-	-	-	-	2,785	16,654
TOTAL RIO PINAR		3,144,434	-	(1,569)	-	-	84,535	3,227,401
SUWANNEE								
341 Structures and Improvements	1.3	926,866	-	-	-	-	18,912	945,779
342 Fuel Holders, Products, and Accessories	3.3	2,373,626	-	-	-	-	178,398	2,552,024
343 Prime Movers	1.3	15,406,279	(1,135,654)	(27,890)	264,551	-	252,324	14,759,611
344 Generators	1.4	4,102,643	-	-	-	-	70,401	4,173,043
345 Accessory Electric Equipment	1.8	1,449,883	-	(4,490)	-	-	39,318	1,484,712
346 Misc. Power Plant Equipment	3.2	78,587	-	-	-	(998)	5,467	83,056
TOTAL SUWANNEE		24,337,884	(1,135,654)	(32,379)	264,551	(998)	564,821	23,998,225
SYSTEM ASSETS 346.0	1.5	188,065	-	-	-	-	6,938	195,003
SYSTEM ASSETS 346.2 (5 YEAR)	20.0	27,962	-	-	-	-	-	27,962

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	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
350									
351	**TOTAL SYSTEM**		216,028	-	-	-	-	6,938	222,965
352									
353	**TIGER BAY**								
354	341 Structures and Improvements	1.7	5,294,354	(17,706)	-	-	-	178,331	5,454,979
355	342 Fuel Holders, Products, and Accessories	1.8	1,993,693	-	-	-	-	54,194	2,047,887
356	343 Prime Movers	1.4	6,106,691	(3,210,615)	-	-	-	655,880	3,551,956
357	344 Generators	1.8	1,106,835	(2,458,424)	-	-	-	183,102	(1,168,488)
358	345 Accessory Electric Equipment	2.1	2,472,918	-	-	-	-	109,668	2,582,586
359	346 Misc. Power Plant Equipment	1.4	998,959	(11,598)	-	-	-	22,397	1,009,758
360	346.2 Misc. Power Plant Equipment (5 Year)	20.0	29,909	-	-	-	-	8,546	38,455
361									
362	**TOTAL TIGER BAY**		18,003,359	(5,698,343)	-	-	-	1,212,117	13,517,133
363									
364	**TURNER**								
365	341 Structures and Improvements	2.0	917,534	-	(2,956)	-	-	30,975	945,553
366	342 Fuel Holders, Products, and Accessories	3.0	2,884,426	-	-	-	-	138,964	3,023,390
367	343 Prime Movers	1.2	8,677,937	-	(52,324)	-	-	172,358	8,797,971
368	344 Generators	2.4	3,254,313	-	-	-	-	118,978	3,373,291
369	345 Accessory Electric Equipment	3.0	1,944,738	(2,247)	-	-	-	72,706	2,015,197
370	346 Misc. Power Plant Equipment	2.1	154,615	-	-	-	-	6,271	160,886
371									
372	**TOTAL TURNER**		17,833,562	(2,247)	(55,280)	-	-	540,252	18,316,288
373									
374	**UNIVERSITY OF FLORIDA**								
375	341 Structures and Improvements	1.8	3,857,351	-	-	-	-	115,515	3,972,865
376	342 Fuel Holders, Products, and Accessories	2.1	3,254,681	(5,908)	(5,392)	-	-	122,113	3,365,495
377	343 Prime Movers	2.5	8,463,282	(219,825)	(104,272)	-	(128,379)	638,449	8,649,255
378	344 Generators	1.8	2,188,603	-	-	-	-	65,296	2,253,899
379	345 Accessory Electric Equipment	1.9	3,014,698	-	(10,700)	-	-	105,029	3,109,027
380	346 Misc. Power Plant Equipment	1.5	642,414	-	-	-	-	15,169	657,584
381	346.2 Misc. Power Plant Equipment (5 Year)	20.0	46,448	-	-	-	-	-	46,448
382									
383	**TOTAL UNIVERSITY OF FLORIDA**		21,467,478	(225,733)	(120,364)	-	(128,379)	1,061,571	22,054,572
384									
385	Other Prod. Retirement work in process		86,799,171		(2,021,470)	45,137,159			129,914,860
386									
387	**TOTAL OTHER PRODUCTION**		673,973,144	(89,454,269)	(6,600,606)	76,373,480	(129,377)	73,384,954	727,547,325
388									
389	**TRANSMISSION PLANT**								
390									
391	350.1 TRANSMISSION EASEMENTS	1.2	17,451,160	-	-	-	-	587,065	18,038,226
392	352 STRUCTURES	1.4	8,473,906	1,017	-	-	(10,263)	471,327	8,935,986
393	353 STATION EQUIPMENT	1.8	126,826,249	(4,823,973)	(3,479,095)	144,945	(38,372)	12,185,470	130,815,223
394	353.2 ENERGY CONTROL CENTER	1.1	32,671,186	(15,638)	107	-	-	424,135	33,079,791
395	354 TOWERS AND FIXTURES	1.3	56,683,697	(17,070)	(188,010)	4,606	-	872,793	57,356,016
396	355 POLES AND FIXTURES	3.3	139,712,719	(3,108,431)	(8,965,765)	210,131	-	18,489,199	146,337,854
397	356 OVERHEAD CONDUCTOR	1.9	128,480,816	(2,910,067)	(6,880,142)	664,497	-	6,956,339	126,311,443
398	357 UNDERGROUND CONDUIT	1.2	6,581,063	-	(1,152)	-	-	374,734	6,954,645
399	358 UNDERGROUND CONDUCTOR	2.0	9,751,294	-	-	-	-	1,456,108	11,207,402

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	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
400	359 MISCELLANEOUS PLANT EQUIP.	0.9	1,178,704	-	-	-	-	29,151	1,207,854
401	Transmission Retirement work in process		(24,477,323)	-	9,318,945	(41,394)	-	-	(15,199,772)
402									
403	**TOTAL TRANSMISSION PLANT**		503,333,471	(10,874,161)	(10,195,113)	982,786	(48,635)	41,846,319	525,044,666
404									
405	**DISTRIBUTION PLANT**								
406	360.1 DISTRIBUTION EASEMENTS	1.4	231,998	-	-	-	-	7,671	239,669
407	361 STRUCTURES	1.4	9,296,696	(6,111)	(25,965)	-	3,550	389,520	9,657,690
408	362 STATION EQUIPMENT	1.8	103,685,983	(3,442,546)	(2,980,224)	1,776,981	288,204	9,983,179	109,311,578
409	364 POLES AND FIXTURES	4.2	306,296,819	(1,250,491)	(3,255,720)	-	116,852	22,763,444	324,670,905
410	365 OVERHEAD CONDUCTOR	2.7	259,386,501	(9,135,499)	(3,350,389)	5,312	212,684	16,684,325	263,802,934
411	366 UNDERGROUND CONDUIT	1.6	39,527,461	(317,430)	(508,186)	60	1,024	3,845,825	42,548,754
412	367 UNDERGROUND CONDUCTOR	3.0	179,826,799	(5,464,165)	(1,005,641)	56,966	1,430	16,591,347	190,006,735
413	368 LINE TRANSFORMER	2.9	264,515,682	(8,412,221)	(88,352)	61,020	1,986	15,397,950	271,476,064
414	369.1 OVERHEAD SERVICES	4.0	65,477,522	(4,508)	-	-	1,798	3,053,019	68,527,832
415	369.2 UNDERGROUND SERVICES	2.2	99,560,184	(681,128)	(118,394)	-	45,636	9,532,150	108,338,448
416	370 METERS	6.0	53,900,023	2,536,799	(429)	-	(1,315,114)	7,554,294	62,675,573
417	371 INSTALL ON CUST. PREM.	3.6	1,902,774	-	-	-	-	141,390	2,044,164
418	373 STREET LIGHTING	3.1	195,730,540	(2,040,668)	(599,953)	478	11,390	9,243,404	202,345,191
419	Distribution Retirement work in process		(13,314,046)	-	(1,236,303)	138,686	-	-	(14,411,663)
420									
421	**TOTAL DISTRIBUTION PLANT**		1,566,024,936	(28,217,968)	(13,169,557)	2,039,504	(630,561)	115,187,519	1,641,233,873
422									
423	**GENERAL PLANT**								
424	390 STRUCTURES	3.7	32,791,657	(443,636)	(268,650)	-	24,045	4,173,138	36,276,555
425	391.1 OFFICE EQUIPMENT	14.3	7,686,206	(3,092,833)	-	-	(120,186)	2,064,854	6,538,042
426	391.2 OFFICE EQUIPMENT	14.3	66,516	-	-	-	-	36,661	103,177
427	391.3 COMPUTERS	14.3	1,812,032	(249,217)	(44)	-	-	944,625	2,507,396
428	391.5 DUPLICATING EQUIPMENT	14.3	(607,538)	-	-	-	-	23,542	(583,996)
429	393 STORES EQUIPMENT	14.3	43,558	-	-	-	-	-	43,558
430	393.1 MOTORIZED HANDLING EQUIP.	14.3	824,214	(83,183)	-	-	-	-	741,031
431	393.2 STORAGE EQUIPMENT	14.3	149,385	(10,009)	-	-	-	48,874	188,249
432	393.3 PORTABLE HANDLING EQUIP.	14.3	139,563	-	-	-	-	255,100	394,663
433	394 TOOLS, SHOP & GARAGE EQUIP.	14.3	1,402,823	(331,151)	-	-	-	538,181	1,609,853
434	394.1 TOOLS, SHOP & GARAGE EQUIP.	14.3	8,141,987	(6,186,872)	-	-	-	-	1,955,114
435	394.2 TOOLS, SHOP & GARAGE EQUIP.	14.3	2,172,500	(600,744)	-	-	-	719,768	2,291,523
436	395.0 LABORATORY EQUIPMENT	14.3	88,685	-	-	-	-	23,624	112,309
437	395.2 PORTABLE LABORATORY EQUIP.	14.3	(892,850)	(62,895)	-	-		73,303	(882,443)
438	396 POWER OPERATED EQUIPMENT	5.8	6,287,694	(5,763)	-	-	-	57,088	6,339,019
439	397 COMMUNICATIONS EQUIPMENT	14.3	8,474,868	(3,263,948)	(22,721)	-	-	3,445,180	8,633,380
440	397.1 COMMUNICATIONS EQUIPMENT	14.3	24,243,934	(22,782,901)	-	-	-	896,581	2,357,614
441	398.2 MISCELLANEOUS EQUIPMENT	14.3	3,775,238	(540,562)	-	-	-	739,493	3,974,169
442	399.1 GENERAL PLT ARO		(3,817,557)	-	-	-	-	195,387	(3,622,170)
443	General Retirement work in process		(1,933,252)	-	(37,831)	(8,250)	-	-	(1,979,333)
444									
445	**TOTAL GENERAL PLANT**		90,849,663	(37,653,715)	(329,246)	(8,250)	(96,141)	14,235,398	66,997,710
446									
447	**TRANSPORTATION EQUIPMENT**								
448	392.1 PASSENGER CARS	8.7	(129,777)	(19,831)	-	-	-	15,066	(134,542)

PROGRESS ENERGY FLORIDA
SUMMARY OF RESERVE TRANSACTIONS - ACCOUNT 108
DECEMBER 31, 2011

Line	DESCRIPTION	DEPRECIATION RATE	RESERVE BALANCE 12/31/2010 (NOTES 1&2)	PLANT RETIRED	REMOVAL COST	SALVAGE	TRANSFER AND ADJUSTMENTS	DEPRECIATION EXPENSE	RESERVE BALANCE 12/31/2011
449	392.2 LIGHT TRUCKS	8.7	4,093,014	(3,429,707)	-	-	-	2,070,426	2,733,733
450	392.3 HEAVY TRUCKS	4.8	2,918,720	(1,651,469)	-	-	-	791,395	2,058,646
451	392.4 SPECIAL EQUIPMENT	5.0	8,326,208	(6,929,162)	-	-	-	3,204,813	4,601,859
452	392.5 TRAILERS	1.7	1,160,874	(440,258)	-	-	-	209,633	930,249
453	392.6 AIRCRAFT (USED)		-	-	-	-	-	-	-
454	392.7 AIRCRAFT (NEW)		(14,407)	-	-	-	-	-	(14,407)
455									
456	**TOTAL TRANSPORTATION EQUIPMENT**		16,354,631	(12,470,427)	-	-	-	6,291,334	10,175,538
457									
458	**TOTAL ELECTRIC PLANT RESERVE**		4,791,009,765	(222,666,672)	(56,968,983)	83,497,739	(4,943,858)	343,077,617	4,933,005,607
459									
460	**ENERGY CONSERVATION EQUIPMENT**								
461	398.1 MISCELLANEOUS	20.0	779,192	(108,122)				358,254	1,029,325
462									
463	**SUBTOTAL**		779,192	(108,122)	-	-	-	358,254	1,029,325
464									
465	**Accum & Amort Other Utility Plant (119)**	various	1,676,111					128,379	1,804,490
466									
467	302 INTANGIBLE PLANT	3.3	1,750,858					281,665	2,032,523
468	303 INTANGIBLE PLANT - CUST SERV SYS	20.0	124,795,643					3,879,571	128,675,214
469									
470	**SUBTOTAL**		126,546,500	-	-	-	-	4,161,236	130,707,736
471									
472	342.9-343.9 GAS CONVERSION	20.0	1,028,672	(4,969)				-	1,023,703
473									
474	**TOTAL ACCOUNT 111 and 119**		130,030,475	(113,090)	-	-	-	4,647,869	134,565,255
475									
476	**TOTAL:**		**4,921,040,240**	**(222,779,763)**	**(56,968,983)**	**83,497,739**	**(4,943,858)**	**347,725,486**	**5,067,570,862**

479 **NOTE 1:** In FERC Docket ER11-3584-000, dated July 15, 2011, the FERC found that PEF must recongnize certain economic effects of the Florida Public Service Commission's (FPSC) rate actions in Docket 090079-EI, March 5, 2010 and June 18, 2010, as Other Regulatory Assets (account 182.3), rather than as adjustments to its Accumulated Depreciation reserves (account 108). As such, PEF was directed to reinstate the adjustments to Accumulated Depreciation reserves and resubmit its FERC Form 1. The amount of the adjustment for 2010 is $65,840,613.

483 **NOTE 2:** Certain balances for 2010 have been reclassified to conform to the 2011 presentation.

Progress Energy

April 30, 2011

Mr. Marshall Willis
Director of the Division of Economic Regulation
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
MWillis@psc.state.fl.us

Dear Mr. Willis,

The Florida Administrative Code 25-6.0142 Uniform Retirement Units for Electric Utilities states the following about additions to a utility's retirement unit listing: "The Director of the Division of Economic Regulation, Florida Public Service Commission, shall be notified annually of additions and subdivisions to the utility's retirement unit List with explanations of the nature and justification."

Progress Energy Florida (PEF) has added several new units of property to its catalog as a result of new technologies utilized at the Crystal River Unit 4 and 5 coal plants. The intent of this letter is to inform you of these additions and explain the nature and justification for the retirement units.

As the Florida Public Service Commission (FPSC) is aware, the U.S. Environmental Protection Agency's (EPA's) federal Clean Air Interstate Rule (CAIR), promulgated in March 2005, imposes restrictions on emissions of both sulfur dioxide (S02) and nitrogen oxides (NOx) from power plants in 28 eastern states and the District of Columbia. As a means to comply with those regulations, PEF has installed 2 flue gas desulfurization systems (FGDs), 2 low NOx burners, and 2 selective catalytic reduction systems (SCRs), which are collectively referred to as "CAIR Assets". PEF has received approval by the FPSC to recover the cost of these CAIR Assets through its Environmental Cost Recovery Clause (ECRC). More details can be found in PEF's Review of Integrated Clean Air Compliance Plan filed in Docket 120007.

The milestones of the CAIR project are as follows:

- Crystal River Unit 5 SCR in service in June 2009;
- Completion of the SCR Common project in July 2009;
- Crystal River Unit 5 FGD in service in December 2009;
- Crystal River FGD Common in service in December 2009; and
- Crystal River Unit 4 SCR/FGD in service in May 2010;

Due to the nature of the new technology used by PEF to install the CAIR Assets, it was necessary to add new property units in order to properly classify the FGD and SCR systems in PEF's property records. The process the project analyst used to determine the units of property applicable to the CAIR Assets involved compiling equipment lists, examining engineering manuals and instrument drawings, and discussing specific functionality with project team engineers. Site tours were also taken to get visuals of the equipment, and the analyst attended the system operations training for FGD.

After the existing and new property units for the CAIR project were identified, the costs of the project were assigned with similar diligence. Working with the vendors on the project, the project analyst obtained detailed cost information and matched the data to the list of property units identified, making reasonable allocations for those costs that were not specifically identified by property unit.

Property Accounting (PA) worked with the CAIR project analyst to discuss the status of the property unit listing and worked through any issues and questions. Once the property unit listing was received, PA compared the list against existing PEF property units under other systems to ensure consistency. PA also reviewed drawings and documentation for the new property units to gain an understanding of the new unit's function as its own system. The results of this review were discussed with management from the business unit and accounting. Based on these analyses, PEF has determined that it is necessary to add two new systems to the property unit records, each containing several new units of property:

- FGD System – 13 new units of property
- SCR System – 6 new units of property

The FGD System: The Wet Flue Gas Desulphurization system treats the flue gas produced by the Crystal River Unit 4 & 5 boilers. Each boiler is provided with a dedicated SO_2 adsorber module, which is capable of removing 97% of the full load sulfer dioxide in the flue gas. By spraying limestone slurry into the flue gas stream, SO_2 is removed when it reacts with the slurry forming calcium sulfite hemi-hydrate ($CaSO_3 - {}^1/_2H_2O$). An in-situ oxidation system provides oxidation air to the adsorber reaction tank. This oxidation system forces calcium sulfite, formed by the SO_2 removal process, to be oxidized to calcium sulfate di-hydrate ($CaSO_4 - 2H_2O$). The calcium and sulfur compounds remain in the slurry as the scrubbed gas passes out of the adsorber and up the Stack. The spent slurry is removed from the adsorber and dewatered to ensure ease of disposal. See Attachment A for a complete listing and description of the FGD property units, the expected useful life, and an explanation of each property unit's function.

The SCR System: The Selective Catalytic Reduction Reactor System reduces boiler flue gas nitrogen oxide (NOx) emissions to nitrogen and water vapor, using ammonia provided by the Urea 2 Ammonia conversion process as a reducing agent. The System includes two 50% economizer outlet ducts which discharge to two SCR inlet ducts. Large particle ash removal devices are located in the economizer ducts to facilitate ash collection in the hoppers. An ammonia injection grid injects ammonia into the flue gas stream for reaction in the SCR. Static mixers are located downstream of the ammonia injection grids to facilitate mixing of the ammonia in the flue gas and homogenize flue gas temperatures at the inlet to the SCR Reactor.

See Attachment B for a complete listing and description of the FGD property units, the expected useful life, and an explanation of each property unit's function.

All the new units of property will be included in FERC account 312 Boiler plant equipment, as shown in Attachment C. The Code of Federal Regulations (CFR) states that "this account shall include the cost installed of furnaces, boilers, coal and ash handling and coal preparing equipment, steam and feed water piping, boiler apparatus and accessories used in the production of steam, mercury, or other vapor, to be used primarily for generating electricity." PEF believes that the CAIR Assets are encompassed by the definition of boiler plant equipment, as explained above.

The process used to identify the new CAIR property units and their conformity with our current property unit listing that we have outlined herein is quite involved and we understand that you may desire more information about that process. Therefore I will be contacting you to determine if a meeting on this topic is mutually desired, as we would be agreeable to discussing this process in further detail.

Respectfully,

Cynthia S. Lee

Cynthia S. Lee
Manager - PEF Regulatory and Property Accounting

Attachments:
A – FGD Systems
B – SCR Systems
C – Selected Portion of Retirement Unit Catalog Including new and Existing Property Units for the Above Systems

Attachment A

FGD Systems

PRI-SYS	CAT
31290	FLUE GAS DESULFURIZATION

Attachment A

SUB	DESC	UNIT	Useful Life	2. What is the cost of the item? The item must cost more than $1,000.	3. How does the item function by itself as a system?	4. Is the item easily identifiable for inventory?	5. In what capacity is the item ordered and intended for use as a system?	6. Give a description of the item.
FGD Retirement Units								
X10	BALL MILL	EACH	Whole System life of the plant	$4M each	A ball mill is a rotating cylindrical vessel used for grinding the limestone required for the formation of limestone slurry used during the SO_2 removal process.	Yes	A ball mill is a rotating cylindrical vessel used for grinding the limestone required for the formation of limestone slurry used during the SO_2 removal process that takes place in the absorber towers.	The ball mill is a rotating horizontal mill which crushes the limestone with high carbon steel grinding balls.
X14	MIST ELIMINATORS	EACH	Whole System life of the plant	$370k each stage	Removes carry-over mist from the scrubbed flue gas exiting the Absorber by inertial impaction.	Yes	As the flue gas exits the absorber, the mist eliminators remove entrained slurry droplets.	The mist eliminators are momentum separation devices that separate high momentum liquid droplets from the gas as it passes through the tortuous path of the mist eliminator chevrons.
X18	WASH WATER SYSTEM	EACH SYS	Whole System life of the plant	$300k each	Keeps the mist eliminators free of slurry deposits by utilizing a spray wash water system.	Yes	Washes the mist eliminators to prevent solids that are formed by evaporation snd slurry psrticle deposits from building up on the blades.	The wash water system is an array of wash headers and wsh nozzles located on the top and bottom sides of the mist eliminators.
X15	SLURRY SPRAY HEADERS	EACH	Whole System life of the plant	$2.2M each	The spray headers take recirculated absorber slurry from the absorber reaction tank and spray it downwards, contercurrent to the gas flow.	Yes	The spray headers spray recirculating slurry from the absorber's integral reaction tank into the flue gas where further sulfur dioxide absorption occurs.	Five interspatial absorber spray headers are located on three different spray levels above the absorber trray. They are made of abrasion and corosion resistant fiberglass reinforced plastic. Each header is feed by slurry by a dedicated absorber recycle pump.
X21	EMERGENCY QUENCH SYSTEM	EACH SYS	Whole System life of the plant	Greater than $1,000.	Quenches the flue gas entering the absorber in event of an air heater failure, a loss of power to the absorber recycle pumps or a Black Plant scenario.	Yes	The emergency quench system is used to quench flue gas to protect the internals of the absorber from exposure to temperatures > 180°F and to protect the inlet from exposure to temperatures > 350°F.	The emergency quench system consists of a series of vertical spray headers arranged in two grids, equipped with spray nozzles that are positioned inside the absorber inlet flue.
X11	WATER SOFTENER	EACH	Whole System life of the plant	Water Softener (oxidation air humidication & cooling) - $120k Water Softener (vacuum pumps) - $677k	Calcium and magnesium precipitate out of water and creates a buildup in the equipment it is being used by. A water softner removes the calcium and magnesium from the water.	Yes	Source of softened water for the absorber oxidation air humidificaion system and the vacuum filter pump seal flush water.	Water flows through a chemical matrix called zeolite which replaces the calcium and magnesium ions in the water with sodium ions.
XX4	SKID, PUMP	EACH SKD	Greater than 5 years.	Greater than $1,000.	The capitalization policy requires that a pump be powered by a driver of over 30 HP to qualify as a retirement unit. These pump skids contain two or more pumps that add up to 30 HP or greater.	Yes	The pump skid is used to transfer a liquid material from one area to another.	Two or more pumps with drivers totaling 30 HP or greater that are mounted on a common skid.
X16	HYDROCYCLONE	EACH	Whole System life of the plant	$180k each	Uses centrifugal force to separate the solids, with the larger, heiver solid particles exiting out of the bottom of the hydrocyclone, and the smaller, lighter solid particles leaving out the top.	Yes	Concentrates the soilds in the gypsum slurry stream prior to feeding the vacuum belt filters for further dewatering.	Holds individual separators in a circular configuration with a central feed chamber.
X16	HYDROCYCLONE	EACH	Whole System life of the plant	$103k each	Uses centrifugal force to separate the solids, with the larger, heiver solid particles exiting out of the bottom of the hydrocyclone, and the smaller, lighter solid particles leaving out the top.	Yes	Decreases the suspended solida concentration of the absorber purge stream prior to being discharged from the FGD system.	Holds individual separators in a circular configuration with a central feed chamber.
XX4	SKID, PUMP	EACH SKD	Greater than 5 years.	Greater than $1,000.	The capitalization policy requires that a pump be powered by a driver of over 30 HP to qualify as a retirement unit. These pump skids contain two or more pumps that add up to 30 HP or greater.	Yes	The pump skid is used to transfer a liquid material from one area to another.	Two or more pumps with drivers totaling 30 HP or greater that are mounted on a common skid.
X12	VACUUM FILTER	EACH	Whole System life of the plant	$2M each	A vacuum is applied to the slurry to remove the water to form gypsum cake.	Yes	A secondary dewatering device used to remove water from the gypsum cake, which is the final Absorber byproduct. As the slurry is evenly fed across the vacuum filter belt, it is then washed to remove chlorides and fines and vacuumed to lower the moisture content to app. 10%.	A horizontal-belt vacuum filter.

Attachment A

SUB	DESC	UNIT	Useful Life	2. What is the cost of the item? The item must cost more than $1,000.	3. How does the item function by itself as a system?	4. Is the item easily identifiable for inventory?	5. In what capacity is the item ordered and intended for use as a system?	6. Give a description of the item.
X13	CAKE WASH SYSTEM	EACH SYS	Whole System life of the plant	Greater than $8.5k	The cake wash system removes chlorides and other disolved solids from the gypsum cake.	Yes	As the slurry moves over the vacuum filter cloth and drainage belt, the cake wash system discharges wash water onto the gypsum cake to remove chlorides and fines (non gypsum particles such as ash and carbon particles).	The cake wash system consists of one FGD cake wash tank and a FGD cake wash pump.
X17	CLOTH WASH SYSTEM	EACH SYS	Whole System life of the plant	Greater than $14.4k	The purpose of the cloth wash system is to supply water to clean the vacuum filter cloth and belt during operation as well as provide lube and seal water to the vacuum pan.	Yes	The cloth wash system suppliesw water to clean the vacuum filter cloth and belt during operation as well as provide lube and seal water to the vacuum pan.	The cloth wash system consists of a pump which provides water from the cloth wash tank to the cloth wash pipes to wash the filter cloth, to the belt wash pipes to wash the filter belt, to the vacuum pam lube piping and to the slide deck lube piping.

Attachment B

SCR Systems

PRI-SYS	CAT
31222	SELECTIVE CATALYTIC REDUCTION SYSTEM
31224	AMMONIA SYSTEM

Attachment B

SCR Retirement Units								
SUB	DESC	UNIT	1. What is the useful life of the item? The useful life must be greater than 1 year.	2. What is the cost of the item? The item must cost more than $1,000.	3. How does the item function by itself as a system?	4. Is the item easily identifiable for inventory?	5. In what capacity is the item ordered and intended for use as a system?	6. Give a description of the item.
XX1	ACCESS DOOR	EACH LEVEL	Life of the SCR Reactor	$10,000 Each Level	Provides access for catalyst removal and installation.	Yes	Each level of the SCR Reactor is equipped with doors for catalyst removal and installation.	Access doors located on each level of the SCR Reactor.
XX2	CATALYST	EACH LAYER	8 years (assumes two washes)	$2.1M Each Layer	The reduction of NOx emission takes place at the catalyst surface by the absorption and reaction of ammonia.	Yes	Each SCR Reactor is designed to accommodate up to three layers of catalyst where the reduction of NOx emission takes place.	Each layer contains 180 catalyst modules which house the ceramic honeycomb catalyst that is highly reactive to NOx. The catalyst is not "consumed" during the DeNOx reaction. However the catalyst performance will decline over time. The catalyst will need to be "washed" to enhance performance. This can be done twice before the catalyst will need to be replaced.
XX3	SONIC HORN	EACH	Life of the SCR Reactor	$5,000 Each Horn	Sonic horns provide regular, in-service, fly ash removal from the catalyst.	Yes	Sonic horns are acoustic cleaners that keep the SCR catalyst free of ash accumulations.	Ten sonic horns per layer for all three SCR catalyst layers.
XX4	SKID, PUMP	EACH SKD	Greater than 5 years.	Greater than $1,000.	The capitalization policy requires that a pump be powered by a driver of over 30 HP to qualify as a retirement unit. These pump skids contain two or more pumps that add up to 30 HP or greater.	Yes	The pump skid is used to transfer a liquid material from one area to another.	Two or more pumps with drivers totaling 30 HP or greater that are mounted on a common skid.
XX5	HYDROLYZER	EACH	20 years	$3.0M – SCR Hydrolyzer, $0.7M – AMM Hydrolyzer	The hydrolyzer uses auxiliary steam to convert urea to ammonia gas.	Yes	The hydrolyzer converts urea to ammonia, which reacts with boiler combustion gases to reduce nitrogen oxide emissions.	The hydrolyzer is a horizontal vessel into which liquid urea is pumped and heated with steam to form ammonia gas.
XX6	INJECTION GRID	EACH	Greater than 10 years.	$3,000	Inject ammonia into the flue gas stream for reaction in the SCR.	Yes	The ammonia injection grid provides thorough injection despersion of ammonia vapor in the flue gas upstream of the SCR Reactors. The ammonia is the reducing agent to reduce boiler flue gas nitrogen oxide emissions to nitrogen and water vapor in the SCR Reactor.	The ammonia injection grid consists of multiple injection lances, each with multiple injection nozzles to inject ammonia into the flue gas stream.

Exhibit 3

Excerpt of Progress Energy Florida

Updated Property Unit Catalog

Including CAIR Property Units

312 22 SELECTIVE CATALYTIC REDUCTION SYSTEM

312 22 812 SCR REACTOR SYSTEM

This system includes components directly associated with the SCR reactor system. The boundaries extend from the economizer outlet up to, and including, the expansion joint to the air heater.

312	22	812	111	EXPANSION JOINT	EACH
312	22	812	120	ANALYZER	EACH
312	22	812	122	DUCT	EACH
312	22	812	123	SPECIAL TOOL	EACH
312	22	812	181	DAMPER	EACH
312	22	812	200	SUPERSTRUCTURE, INC STEEL & CONCRETE	EACH
312	22	812	205	LIGHTING SYSTEM	EACH SYS
312	22	812	208	ELEVATOR	EACH
312	22	812	209	FIRE PROTECTION SYSTEM	EACH SYS
312	22	812	214	HOIST	EACH
312	22	812	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	22	812	218	FOUNDATION	EACH
312	22	812	225	VALVE	EACH
312	22	812	271	CONTROL SYSTEM	EACH SYS
312	22	812	287	MONITOR	EACH
312	22	812	305	LADDERS/PLATFORMS	EACH ELEVAT
312	22	812	338	SCREEN	EACH
312	22	812	341	DRAINAGE SYSTEM, COMPLETE	EACH SYS
312	22	812	435	RECTIFIER	EACH
312	22	812	446	INSULATION & LAGGING	EACH SYS
312	22	812	810	ACCESS DOOR	EACH
312	22	812	811	CATALYST	EACH LAYER

312 22 813 SONIC HORN SYSTEM

This system includes installations associated with the sonic horns. The boundaries extend from the first isolation valve after the control air receiver tanks 544-TNK-0001 and 544-TNK-0002 throughout the SCR Reactor units.

312	22	813	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	24	813	224	TANK	EACH
312	22	813	271	CONTROL SYSTEM	EACH SYS
312	22	813	812	SONIC HORN	EACH

312 22 814 SEAL AIR SYSTEM

This system includes installations associated with the furnishing of air to seal to the SCR system. The boundaries are from the hot secondary air duct to the connections to the SCR reactor system.

312	22	814	111	EXPANSION JOINT	EACH
312	22	814	122	DUCT	EACH
312	22	814	181	DAMPER	EACH
312	22	814	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	22	814	271	CONTROL SYSTEM	EACH SYS
312	22	814	423	INSULATION/LAGGING	ALL

312 24 AMMONIA SYSTEM

312 24 816 UREA UNLOADING AND STORAGE

This system includes those components associated with the urea unloading and storage system. The boundaries for this system are from the rail and truck unloading station to the pump suction of the urea transfer pumps.

312	24	816	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	24	816	213	HEATING SYSTEM	EACH SYS
312	24	816	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	24	816	216	PUMP, COMPLETE	EACH
312	24	816	218	FOUNDATION	EACH
312	24	816	224	TANK	EACH
312	24	816	271	CONTROL SYSTEM	EACH SYS
312	24	816	274	AGITATOR	EACH
312	24	816	341	DRAINAGE SYSTEM, COMPLETE	EACH SYS
312	24	816	423	INSULATION & LAGGING	EACH SYS
312	24	816	813	SKID, PUMP	EACH SKD

312 24 817 AMMONIA HYDROLYZER SYSTEM

This system includes those components directly related to the ammonia hydrolyzer system. The boundaries extend from the urea transfer pump skid suction to the ammonia flow control units (AFCU) and the hydrolyzer blowdown tanks. It also includes the urea steam saturator and the urea condensate return.

312	24	817	114	FAN/BLOWER, COMPLETE	EACH
312	24	817	120	ANALYZER	EACH
312	24	817	146	CONTROL PANEL	EACH
312	24	817	189	HEAT EXCHANGER, TUBE BUNDLE	EACH
312	24	817	205	LIGHTING SYSTEM, COMPLETE	EACH SYS
312	24	817	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	24	817	213	HEATING SYSTEM	EACH SYS
312	24	817	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	24	817	216	PUMP, COMPLETE	EACH
312	24	817	218	FOUNDATION	EACH
312	24	817	224	TANK	EACH
312	22	817	225	VALVE	EACH
312	24	817	271	CONTROL SYSTEM	EACH SYS
312	22	817	377	COOLER	EACH
312	24	817	423	INSULATION & LAGGING	EACH SYS
312	24	817	490	HEATER	EACH
312	24	817	623	ACCUMULATOR	EACH
312	24	817	708	MIXER	EACH
312	24	817	813	SKID, PUMP	EACH SKD
312	24	817	814	HYDROLYZER	EACH

312 24 818 AMMONIA INJECTION SYSTEM

This system includes components directly associated with the ammonia injection system. The boundaries extend from the ammonia flow control units (AFCU) to the injection grids.

312	24	818	114	FAN/BLOWER, COMPLETE	EACH
312	24	818	121	METER	EACH
312	24	818	213	HEATING SYSTEM	EACH SYS
312	24	818	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	24	818	225	VALVE	EACH
312	24	818	271	CONTROL SYSTEM	EACH SYS
312	24	818	490	HEATER	EACH

312	24	818	708	MIXER	EACH
312	24	818	815	INJECTION GRID	EACH

312 90 FGDS

312 90 251 LIMESTONE BALL MILL SYSTEM

This system includes those components directly related to the ball mills. The boundaries extend from the connection below the weigh feeder hoppers and below the filtrate water inlet to ball mills to the connection before the inlet header at the limestone slurry storage tanks.

312	90	251	038	BIN	EACH
312	90	251	121	METER	EACH
312	90	251	135	REDUCTION GEAR	EACH
312	90	251	158	LINER	EACH
312	90	251	180	LUBE OIL SYSTEM	EACH
312	90	251	195	HOPPER (BALL CHARGE)	EACH
312	90	251	205	LIGHTING SYSTEM, COMPLETE	EACH SYS
312	90	251	208	ELEVATOR	EACH
312	90	251	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	251	213	HEATING SYSTEM	EACH SYS
312	90	251	214	HOIST	EACH
312	90	251	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	251	216	PUMP, COMPLETE	EACH
312	90	251	218	FOUNDATION	EACH
312	90	251	224	TANK	EACH
312	90	251	225	VALVE	EACH
312	90	251	271	CONTROL SYSTEM	EACH SYS
312	90	251	274	AGITATOR	EACH
312	90	251	287	MONITOR	EACH
312	90	251	336	CHUTE WITH LINER	EACH
312	90	251	406	CLASSIFIER	EACH
312	90	251	426	LEVEL INDICATOR	EACH
312	90	251	436	BEARING	EACH
312	90	251	468	CRANE	EACH
312	90	251	572	SEPARATOR	EACH
312	90	251	709	GEAR BOX	EACH
312	90	251	816	BALL MILL	EACH

312 90 252 LIMESTONE SLURRY SYSTEM

This system includes those components directly associated with the limestone slurry system. The boundaries extend from the first connection before the limestone slurry tank header to the limestone slurry feed to absorber reaction tank nozzle.

312	90	252	205	LIGHTING SYSTEM, COMPLETE	EACH SYS
312	90	252	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	252	213	HEATING SYSTEM	EACH SYS
312	90	252	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	252	216	PUMP, COMPLETE	EACH
312	90	252	218	FOUNDATION	EACH
312	90	252	224	TANK	EACH
312	90	252	225	VALVE	EACH
312	90	252	271	CONTROL SYSTEM	EACH SYS

312	90	252	274	AGITATOR	EACH
312	90	252	287	MONITOR	EACH
312	90	252	426	LEVEL INDICATOR	EACH

312 90 253 LIMESTONE SILO AND FEEDER SYSTEM

This system includes those components directly associated with the limestone silos and feeders. The boundaries extend from the limestone silos inlet to the ball mills.

312	90	253	114	FAN/BLOWER	EACH
312	90	253	172	DUST COLLECTION SYSTEM	EACH SYS
312	90	253	200	SUPERSTRUCTURE, INC STEEL & CONCRETE	EACH
312	90	253	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	253	218	FOUNDATION	EACH
312	90	253	271	CONTROL SYSTEM	EACH SYS
312	90	253	287	MONITOR	EACH
312	90	253	336	CHUTE WITH LINER	EACH
312	90	253	407	FEEDER	EACH
312	90	253	418	SILO/BUNKER	EACH
312	90	253	426	LEVEL INDICATOR	EACH

312 90 301 LIMESTONE AND GYPSUM HANDLING - CONVEYOR SYSTEMS (LIMESTONE, GYPSUM)

This system includes installations associated with the movement of limestone or gypsum via conveyor.

312	90	301	123	SPECIAL TOOL	EACH
312	90	301	135	REDUCTION GEAR	EACH
312	90	301	152	COMPRESSOR	EACH
312	90	301	172	DUST COLLECTION SYSTEM	EACH SYS
312	90	301	195	HOPPER	EACH
312	90	301	202	ROOF	EACH
312	90	301	205	LIGHTING SYSTEM, COMPLETE	EACH
312	90	301	209	FIRE PROTECTION SYSTEM, COMPLETE	EACH
312	90	301	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	301	213	HEATING SYSTEM	EACH SYS
312	90	301	214	HOIST	EACH
312	90	301	218	FOUNDATION	EACH
312	90	301	271	CONTROL SYSTEM	EACH SYS
312	90	301	281	METAL DETECTOR	EACH
312	90	301	287	MONITOR	EACH
312	90	301	297	UNLOADER STRUCTURE	EACH
312	90	301	322	CONVEYOR	EACH
312	90	301	331	WEIGHING DEVICE/SCALE	EACH
312	90	301	332	SAMPLING SYSTEM	EACH
312	90	301	333	METAL DETECTION SYSTEM	EACH SYS
312	90	301	334	MAGNETIC SEPARATOR SYSTEM	EACH SYS
312	90	301	335	TRANSFER STATION	EACH
312	90	301	336	CHUTE WITH LINER	EACH
312	90	301	337	VIBRATOR/AIR CANNON	EACH
312	90	301	338	SCREEN	EACH
312	90	301	339	STORAGE AREA	EACH
312	90	301	340	TRUCK ASSEMBLY	EACH
312	90	301	349	CRUSHER/BREAKER	EACH
312	90	301	387	BELT CLEANING UNIT	EACH
312	90	301	407	FEEDER	EACH
312	90	301	709	GEAR BOX	EACH

312	90	301	784	BELT TURNAROUND UNIT	EACH
312	90	301	785	BELT TENSIONING SYSTEM	EACH SYS

312 90 302 LIMESTONE AND GYPSUM HANDLING - LIVE STORAGE SYSTEM

This system includes components associated with the live storage of limestone and gypsum. The boundaries extend from and including limestone storage are to the L-1 conveyor. The boundaries also include gypsum storage after the G-2 belt.

312	90	302	157	VIBRATOR	EACH
312	90	302	158	LINER	EACH
312	90	302	195	HOPPER	EACH
312	90	302	200	SUPERSTRUCTURE, INC STEEL & CONCRETE	EACH
312	90	302	202	ROOF	EACH
312	90	302	206	HVAC SYSTEM	EACH
312	90	302	209	FIRE PROTECTION SYSTEM, COMPLETE	EACH
312	90	302	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	302	216	PUMP, COMPLETE	EACH
312	90	302	218	FOUNDATION	EACH
312	90	302	248	CONTROL GATE	EACH
312	90	302	271	CONTROL SYSTEM	EACH SYS
312	90	302	341	DRAINAGE SYSTEM	EACH SYS
312	90	302	350	TRIPPER TRACKS	EACH
312	90	302	351	TRIPPER CARRIAGE	EACH
312	90	302	418	SILO/BUNKER	EACH
312	90	302	785	BELT TENSIONING SYSTEM	EACH SYS

312 90 401 ABSORBER TOWER SYSTEM

This system includes those components directly associated with the absorber tower. The boundaries extend from the absorber side of the expansion joint on the inlet to the absorber tower to and including the expansion joint to the stack. This system includes the reaction tank, absorber pressure and temperature measuring devices, absorber sprays and tray, 1st and 2nd stage mist eliminators and wash water system, and reaction tank agitators.

312	90	401	017	HOOD	EACH
312	90	401	102	MOISTURE SEPARATOR	EACH
312	90	401	111	EXPANSION JOINT	EACH
312	90	401	114	FAN/BLOWER	EACH
312	90	401	120	ANALYZER	EACH
312	90	401	122	DUCT	EACH
312	90	401	135	REDUCTION GEAR	EACH
312	90	401	200	SUPERSTRUCTURE, INC STEEL & CONCRETE	EACH
312	90	401	205	LIGHTING SYSTEM, COMPLETE	EACH SYS
312	90	401	206	HVAC SYSTEM	EACH
312	90	401	208	ELEVATOR	EACH
312	90	401	209	FIRE PROTECTION SYSTEM, COMPLETE	EACH
312	90	401	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	401	214	HOIST	EACH
312	90	401	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	401	216	PUMP, COMPLETE	EACH
312	90	401	218	FOUNDATION	EACH
312	90	401	224	TANK	EACH
312	90	401	225	VALVE	EACH
312	90	401	271	CONTROL SYSTEM	EACH SYS
312	90	401	274	AGITATOR	EACH
312	90	401	287	MONITOR	EACH

312	90	401	341	DRAINAGE SYSTEM	EACH SYS
312	90	401	426	LEVEL INDICATOR	EACH
312	90	401	446	INSULATION/LAGGING	ALL
312	90	401	466	TRAY	ALL
312	90	401	468	CRANE	EACH
312	90	401	490	HEATER	EACH
312	90	401	817	MIST ELIMINATORS	EACH
312	90	401	818	SLURRY SPRAY HEADERS	EACH
312	90	401	819	WASH WATER SYSTEM	EACH SYS

312 90 402 OXIDATION AIR SYSTEM

This system includes those components directly associated with the oxidation air system. The boundaries of this system are from the ductwork leading to the oxidation air blower inlet to the flange connection at the absorber reaction tank.

312	90	402	110	SILENCER/MUFFLER	EACH
312	90	402	114	FAN/BLOWER	EACH
312	90	402	135	REDUCTION GEAR	EACH
312	90	402	180	LUBE OIL SYSTEM	EACH
312	90	402	181	DAMPER	EACH
312	90	402	200	SUPERSTRUCTURE, INC STEEL & CONCRETE	EACH
312	90	402	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	402	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	402	218	FOUNDATION	EACH
312	90	402	225	VALVE	EACH
312	90	402	274	AGITATOR	EACH
312	90	402	287	MONITOR	EACH
312	90	402	291	FILTER	EACH
312	90	402	341	DRAINAGE SYSTEM	EACH SYS

312 90 403 ABSORBER RECYCLE PUMPS

This system includes those components directly associated with the absorber recycle system. The boundaries of this system are from the absorber recycle pump suction gate valve to the flange connection before the absorber spray headers.

312	90	403	111	EXPANSION JOINT	EACH
312	90	403	135	REDUCTION GEAR	EACH
312	90	403	180	LUBE OIL SYSTEM	EACH
312	90	403	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	403	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	403	216	PUMP, COMPLETE	EACH
312	90	403	218	FOUNDATION	EACH
312	90	403	225	VALVE	EACH
312	90	403	287	MONITOR	EACH

312 90 404 ABSORBER HYDRAULIC POWER

This system includes those components directly associated with the hydraulic power skid.

312	90	404	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	404	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	404	216	PUMP, COMPLETE	EACH
312	90	404	218	FOUNDATION	EACH
312	90	404	224	TANK	EACH
312	90	404	225	VALVE	EACH
312	90	404	287	MONITOR	EACH
312	90	404	373	HYDRAULIC POWER UNIT	EACH

312 90 405 DBA ADDITIVE SYSTEM

This system includes those components directly associated with the dibasic acid additive system.

312	90	405	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	405	216	PUMP, COMPLETE	EACH
312	90	405	218	FOUNDATION	EACH
312	90	405	224	TANK	EACH
312	90	405	225	VALVE	EACH
312	90	405	274	AGITATOR	EACH
312	90	405	426	LEVEL INDICATOR	EACH
312	90	405	490	HEATER	EACH
312	90	405	813	SKID, PUMP	EACH SKD

312 90 451 ABSORBER BLEED PUMP SYSTEM

This system includes those components directly associated with the absorber bleed pump system. The boundaries for this system are from the absorber reaction tank nozzle to the discharge isolation valve for the absorber primary hydrocyclone and emergency hold tank.

312	90	451	121	METER	EACH
312	90	451	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	451	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	451	216	PUMP, COMPLETE	EACH
312	90	451	218	FOUNDATION	EACH
312	90	451	224	TANK	EACH
312	90	451	225	VALVE	EACH
312	90	451	287	MONITOR	EACH

312 90 452 ABSORBER PRIMARY HYDROCYCLONE

This system includes those components directly associated with the primary hydrocyclone system. The boundaries for this system are from the absorber bleed pump discharge block valve to the secondary hydrocyclone block valve.

312	90	452	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	452	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	452	216	PUMP, COMPLETE	EACH
312	90	452	218	FOUNDATION	EACH
312	90	452	224	TANK	EACH
312	90	452	225	VALVE	EACH
312	90	452	274	AGITATOR	EACH
312	90	452	287	MONITOR	EACH
312	90	452	291	FILTER	EACH
312	90	452	426	LEVEL INDICATOR	EACH
312	90	452	572	SEPARATOR	EACH
312	90	452	821	HYDROCYCLONE	EACH

312 90 453 ABRORBER SECONDARY HYDROCYCLONE

This system includes those components directly associated with the absorber purge hydrocyclone system. The boundaries for this system are from the primary hydrocyclone feed pump discharge block valve to the last connection before the waste water settling pond.

312	90	453	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	453	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	453	216	PUMP, COMPLETE	EACH
312	90	453	218	FOUNDATION	EACH
312	90	453	224	TANK	EACH

312	90	453	225	VALVE	EACH
312	90	453	274	AGITATOR	EACH
312	90	453	287	MONITOR	EACH
312	90	453	426	LEVEL INDICATOR	EACH
312	90	453	572	SEPARATOR	EACH
312	90	453	813	SKID, PUMP	EACH SKD
312	90	453	821	HYDROCYCLONE	EACH

312 90 502 VACUUM FILTER SYSTEM

This system includes those components directly associated with the vacuum filter system. The boundaries for this system are from the primary hydrocyclone overflow to the last connection before the filtrate tank.

312	90	502	042	RECEIVER	EACH
312	90	502	135	REDUCTION GEAR	EACH
312	90	502	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	502	214	HOIST	EACH
312	90	502	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	502	216	PUMP, COMPLETE	EACH
312	90	502	218	FOUNDATION	EACH
312	90	502	224	TANK	EACH
312	90	502	225	VALVE	EACH
312	90	502	271	CONTROL SYSTEM	EACH SYS
312	90	502	274	AGITATOR	EACH
312	90	502	287	MONITOR	EACH
312	90	502	330	BELT	EACH
312	90	502	336	CHUTE WITH LINER	EACH
312	90	502	341	DRAINAGE SYSTEM	EACH SYS
312	90	502	572	SEPARATOR	EACH
312	90	502	822	VACUUM FILTER	EACH
312	90	502	823	CAKE WASH SYSTEM	EACH SYS
312	90	502	824	CLOTH WASH SYSTEM	EACH SYS

312 90 550 BLOWDOWN SYSTEM

This system includes those components directly associated with the blowdown system. The boundaries for this system are from the connection before the blowdown tank to the FGD wastewater settling pond.

312	90	550	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	550	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	550	216	PUMP, COMPLETE	EACH
312	90	550	218	FOUNDATION	EACH
312	90	550	224	TANK	EACH
312	90	550	225	VALVE	EACH
312	90	550	274	AGITATOR	EACH
312	90	550	287	MONITOR	EACH
312	90	550	426	LEVEL INDICATOR	EACH

312 90 551 FILTRATE TANK SYSTEM

This system includes those components directly associated with the filtrate tank system. The boundaries for this system are from the connection before the filtrate tank to the absorber reaction tank and the limestone classifiers and limestone ball mill storage tanks.

312	90	551	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	551	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	551	216	PUMP, COMPLETE	EACH

312	90	551	218	FOUNDATION	EACH
312	90	551	224	TANK	EACH
312	90	551	225	VALVE	EACH
312	90	551	274	AGITATOR	EACH
312	90	551	287	MONITOR	EACH
312	90	551	426	LEVEL INDICATOR	EACH

312 90 552 EMERGENCY STORAGE TANK SYSTEM

This system includes those components directly associated with the emergency storage tank system. The boundaries for this system are from the inlet valve from the absorber bleed pump and absorber area sump pump to the last connection point before the absorber reaction tank.

312	90	552	180	LUBE OIL SYSTEM	EACH
312	90	552	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	552	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	552	216	PUMP, COMPLETE	EACH
312	90	552	218	FOUNDATION	EACH
312	90	552	224	TANK	EACH
312	90	552	225	VALVE	EACH
312	90	552	274	AGITATOR	EACH
312	90	552	287	MONITOR	EACH
312	90	552	426	LEVEL INDICATOR	EACH

312 90 601 LIMESTONE PREPARATION AREA SUMP SYSTEM

This system includes those components directly associated with the limestone preparation are sumps. The boundaries for this system are from the limestone preparation area sump pump to the limestone slurry storage tank.

312	90	601	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	601	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	601	216	PUMP, COMPLETE	EACH
312	90	601	218	FOUNDATION	EACH
312	90	601	225	VALVE	EACH
312	90	601	271	CONTROL SYSTEM	EACH SYS
312	90	601	274	AGITATOR	EACH
312	90	601	426	LEVEL INDICATOR	EACH

312 90 602 ABSORBER AREA SUMP SYSTEM

This system includes those components directly associated with the absorber area sumps. The boundaries for this system are from each unit absorber area sump pump to each unit absorber reaction tank.

312	90	602	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	602	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	602	216	PUMP, COMPLETE	EACH
312	90	602	218	FOUNDATION	EACH
312	90	602	225	VALVE	EACH
312	90	602	274	AGITATOR	EACH
312	90	602	426	LEVEL INDICATOR	EACH

312 90 603 DEWATERING AREA SUMP SYSTEM

This system includes those components directly associated with the dewatering area sumps. The boundaries for this system are from the dewatering area sump pump to the filtrate tanks.

312	90	603	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	603	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	603	216	PUMP, COMPLETE	EACH
312	90	603	218	FOUNDATION	EACH
312	90	603	225	VALVE	EACH
312	90	603	274	AGITATOR	EACH
312	90	603	426	LEVEL INDICATOR	EACH

312 90 650 WELL WATER SUPPLY SYSTEM

This system includes components associated with the supply of well water to the flue gas desulfurization process. The system is bounded at the inlet piping connections closest to the various FGD pump seals, tanks, pumps, filter assemblies and heat exchangers, the ball mill and the absorber tower system.

312	90	650	121	METER	EACH
312	90	650	205	LIGHTING SYSTEM, COMPLETE	EACH
312	90	650	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	650	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	650	216	PUMP, COMPLETE	EACH
312	90	650	218	FOUNDATION	EACH
312	90	650	224	TANK	EACH
312	90	650	225	VALVE	EACH
312	90	650	271	CONTROL SYSTEM	EACH SYS
312	90	650	272	ENCLOSURE	EACH
312	90	650	273	WELL	EACH
312	90	650	287	MONITOR	EACH

312 90 700 FGD SERVICE WATER SYSTEM

This system includes components associated with the supply of non-potable service water to FGD related systems and common equipment within the FGD systems. Well water is the source of FGD service water.

312	90	700	121	METER	EACH
312	90	700	212	DRIVE, ELEC. MOTOR (COMPLETE)	EACH
312	90	700	215	PIPING, RUN BETWEEN TERMINATIONS	RUN
312	90	700	216	PUMP, COMPLETE	EACH
312	90	700	224	TANK	EACH
312	90	700	225	VALVE	EACH
312	90	700	287	MONITOR	EACH
312	90	700	426	LEVEL INDICATOR	EACH
312	90	700	825	WATER SOFTENER	EACH