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

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
El Paso Electric Company	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).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
El Paso Electric Company	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)*
P.O. Box 982, El Paso, TX 79960-0982; 100 North Stanton, El Paso, TX 79901

05 Name of Contact Person	06 Title of Contact Person
Nathan T. Hirschi	Vice President & Controller

07 Address of Contact Person *(Street, City, State, Zip Code)*
P.O. Box 982, El Paso, TX 79960-0982; 100 North Stanton, El Paso, TX 79901

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(915) 521-4456	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012

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)*
Nathan T. Hirschi		
02 Title		
Vice President & Controller	Nathan T. Hirschi	04/09/2012

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	Not Applicable
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	None
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	None
25	Unrecovered Plant and Regulatory Study Costs	230	None
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	Not Applicable
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	Not Applicable
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	None
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	Not Applicable
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	Not Applicable
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	Not Applicable
64	Pumped Storage Generating Plant Statistics	408-409	Not Applicable
65	Generating Plant Statistics Pages	410-411	Not Applicable
66	Transmission Line Statistics Pages	422-423	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	None
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	None
70	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.

Nathan T. Hirschi
Vice President & Controller
Stanton Tower, 100 North Stanton
El Paso, Texas 79901

Mailing Address:
Nathan T. Hirschi
Post Office Box 982
El Paso, Texas 79960-0982

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.

Texas - August 30, 1901

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 power generation, transmission and distribution for sale at retail in the states of Texas and New Mexico; and wholesale sales including sales for resale to other electric utilities primarily in the states of Texas, New Mexico and Arizona and sales for resale to power marketers.

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

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 beneficieearies for whom trust was maintained, and purpose of the trust.

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)
1	MiraSol Energy Services, Inc.	Energy efficiency products		
2		and services	100%	
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Schedule Page: 103 Line No.: 1 Column: a

MiraSol, which began operations as a separate subsidiary in March 2001, provided energy efficiency generating units and products and discontinued new activities in 2002.

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	Interim Chief Executive Officer	Thomas V. Shockley III	
2	Senior Vice President and Chief Financial Officer	David G. Carpenter	334,304
3	Senior Vice President - General Counsel		
4	and Chief Compliance Officer	Mary E. Kipp	277,692
5	Senior Vice President - Corporate Planning		
6	and Development	Rocky R. Miracle	262,061
7	Senior Vice President - Operations	Hector R. Puente	252,526
8	Vice President - System Operations and Planning	Steven T. Buraczyk	205,785
9	Vice President - Treasurer	Steven P. Busser	207,178
10	Vice President - Transmission and Distribution	Robert C. Doyle	173,802
11	Vice President and Controller	Nathan T. Hirschi	216,397
12	Vice President - Customer Care	Kerry B. Lore	190,624
13	Vice President - Power Generation	Andres R. Ramirez	217,432
14	Corporate Secretary	Guillermo Silva, Jr.	145,230
15	Vice President - Power Marketing and Fuels	John A. Whitacre	206,926
16	Chief Executive Officer	David W. Stevens	596,923
17	Senior Vice President - Customer Care and		
18	External Affairs	Richard G. Fleager	247,306
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Schedule Page: 104 Line No.: 1 Column: b

On January 30, 2012, the Board of Directors of the Company appointed Thomas V. Shockley III as the Company's interim Chief Executive Officer while a search is conducted to replace Mr. Stevens. Mr. Shockley, is a veteran electric utility executive and a member of the Company's Board of Directors since May 2010. During his service as interim Chief Executive Officer, Mr. Shockley is paid $50,000 per month.

Schedule Page: 104 Line No.: 7 Column: b

On May 6, 2011, the Company appointed Hector R. Puente as Senior Vice President of Operations. Mr. Puente had been Vice President - Transmission and Distribution since May 2006.

Schedule Page: 104 Line No.: 8 Column: b

On January 24, 2011, the Company appointed Steven T. Buraczyk as Vice President – System Operations and Planning. Mr. Buraczyk had been Vice President – Power Marketing and Fuels since July 2008.

Schedule Page: 104 Line No.: 9 Column: b

On January 24, 2011, the Company appointed Steven P. Busser as Vice President - Treasurer. Mr. Busser had been Vice President - Treasurer and Chief Risk Officer since May 2006.

Schedule Page: 104 Line No.: 10 Column: b

On June 20, 2011, the Company appointed Robert C. Doyle as Vice President - Transmission and Distribution. Mr. Doyle had been Vice President - New Mexico Affairs since February 2007.

Schedule Page: 104 Line No.: 15 Column: b

On January 24, 2011, the Company appointed John A. Whitacre as Vice President – Power Marketing and Fuels. Mr. Whitacre had been Vice President – System Operations and Planning since May 2006.

Schedule Page: 104 Line No.: 16 Column: b

On January 30, 2012, David W. Stevens resigned from his position as Chief Executive Officer of the Company, effective March 2, 2012, and as a Director immediately.

Schedule Page: 104 Line No.: 18 Column: b

On April 2, 2012, Richard G. Fleager resigned from his position as Senior Vice President - Customer Care and External Affairs, effective immediately.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Catherine A. Allen - Director	The Santa Fe Group
2		3 Chamisa Drive North, Suite 2
3		Santa Fe, New Mexico 87508
4		
5	John Robert Brown - Director	Brownco Capital, L.L.C.
6		123 W. Mills, Suite 610
7		El Paso, Texas 79901
8		
9	James W. Cicconi - Director	AT&T
10		1120 20th Street, N.W., Suite 1000
11		Washington, D.C. 20036
12		
13	James W. Harris - Director***	Seneca Financial Group, Inc.
14		Post Office Box 38
15		Manns Harbor, North Carolina 27953
16		
17	Kenneth R. Heitz - Director and Chairman of the Board	Irell & Manella, LLP
18		1800 Avenue of the Stars, Suite 900
19		Los Angeles, California 90067-4276
20		
21	Patricia Z. Holland-Branch - Director	Facilities Connection, Inc.
22		240 East Sunset
23		El Paso, Texas 79922
24		
25	Michael K. Parks - Director and Vice Chairman of	Crescent Capital Group LP
26	the Board***	11100 Santa Monica Blvd., Suite 2000
27		Los Angeles, California 90025
28		
29	Thomas V. Shockley III - Director	602 Cimarron Hills Trail West
30		Georgetown, Texas 78628
31		
32	Eric B. Siegel - Director**	11100 Santa Monica Blvd., Suite 2000
33		Los Angeles, California 90025
34		
35	David W. Stevens - Director and CEO	El Paso Electric Company
36		100 N. Stanton
37		El Paso, Texas 79901
38		
39	Stephen N. Wertheimer - Director***	W Capital Partners
40		One East 52nd Street
41		New York, New York 10022
42		
43	Charles A. Yamarone - Director	Houlihan Lokey
44		10250 Constellation Blvd., 5th Floor
45		Los Angeles, California 90067
46		
47		
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Schedule Page: 105 Line No.: 29 Column: a

On January 30, 2012, the Board of Directors of the Company appointed Thomas V. Shockley III as the Company's interim Chief Executive Officer while a search is conducted to replace Mr. Stevens. Mr. Shockley, is a veteran electric utility executive and a member of the Company's Board of Directors since May 2010.

Schedule Page: 105 Line No.: 35 Column: a

On April 8, 2011, at a joint Audit, Compensation and Nominating & Corporate Governance Committee meeting, Mr. Stevens was appointed to serve on the Executive Committee.

On January 30, 2012, Mr. Stevens resigned from his position as Chief Executive Officer of the Company, effective March 2, 2012, and as a Director immediately.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
1	Rate Schedule FERC No. 18	ER08-742-001
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
1	20110810-0021	08/05/2011	ER08-742-000	2011 Annual Update	18
2		08/09/2011			
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Schedule Page: 1061 Line No.: 1 Column: d

The 2011 annual update is to the cost-based formula rate included in the Power Sales Agreement under ER08-742.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
1	N/A			
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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:

   None

2. Acquisition of Ownership in Other Companies:

   None

3. Purchase or Sale of an Operating Unit or System:

   None

4. Important Leaseholds That Have Been Acquired or Given, Assigned or Surrendered:

   None

5. Important Extension or Reduction of Transmission or Distribution System:

   None

6. Obligations Incurred as a Result of Issuance of Securities or Assumption of Liabilities or Guarantees:

Revolving Credit Facility and Guarantee of Debt. In October 2011, the Company received final approval from the NMPRC in Case No. 11-00349-UT and from the FERC in Docket No. ES11-43-000 to amend and restate the Company's $200 million revolving credit facility ("RCF"), which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016.

On March 29, 2012, the Company and The Bank of New York Mellon Trust Company, N.A., as trustee of the Rio Grande Resources Trust, entered into the Incremental Facility Assumption Agreement (the "Assumption Agreement") related to the RCF discussed above with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, Union Bank, N.A., as syndication agent, and various lending banks party thereto. The Assumption Agreement provides for the Company's exercise in full of the accordion feature provided for under the RCF, increasing the aggregate unsecured borrowing available from $200 million to $300 million. In addition, the Assumption Agreement reflects the addition of a new lender under the RCF. No other material modifications have been made to the terms and conditions of the RCF.

7. Changes in Articles of Incorporation:

None

8. Important Wage Scale Changes:

Base salaries for non-union employees were increased by an average of 3.0% effective in January 2011 compared to 2010 through the merit award process. The annual effect of this increase was approximately $1.2 million. Base salaries for union employees under contract were increased by an average of 3.0% effective in September 2011 compared to 2010. The annual effect of this increase was approximately $0.8 million.

9. Materially Important Legal Proceedings (see also Notes C and L of "Notes to Financial Statements"):

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, to the extent that the Company has been able to reach a conclusion as to its ultimate liability, it believes that none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from the Luna Energy Facility ("LEF") located near Deming, New Mexico to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006, and hearings on the disputed issues were held before an administrative law judge. In the initial decision dated September 6, 2007, the administrative law judge found that the Transmission Agreement allows TEP to transmit power from the LEF to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from

Luna to Greenlee. The Company and TEP filed exceptions to the initial decision.

On November 13, 2008, the FERC issued an order on the initial decision finding that the transmission rights given to TEP in the Transmission Agreement are firm and are not restricted for transmission of power from Springerville as the receipt point to Greenlee as the delivery point. Therefore, pursuant to the order, TEP can use its transmission rights granted under the Transmission Agreement to transmit power from the LEF to either Springerville or Greenlee so long as it transmits no more than 200 MW over all segments at any one time.

The FERC also ordered that the Company refund to TEP all sums with interest that TEP had paid it for transmission under the applicable transmission service agreements since February 2006 for service relating to the LEF. On December 3, 2008, the Company refunded $9.7 million to TEP. The Company had established a reserve for the rate refund of approximately $7.2 million as of September 30, 2008, resulting in a pre-tax charge to earnings of approximately $2.5 million in 2008. The Company also paid TEP interest on the refunded balance of approximately $0.9 million, which was also charged to earnings in 2008. The Company filed a request for rehearing of the FERC's decision on December 15, 2008, seeking reversal of the order on the merits and a return of any refunds made in the interim, as well as compensation for all service that the Company may provide to TEP from the LEF over the Company's transmission system on a going forward basis. On July 7, 2010, the FERC denied the Company's request for rehearing. On July 23, 2010, the Company filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the "Court of Appeals") and on August 18, 2010, TEP filed a motion to intervene in the proceeding. On January 14, 2011, the Company and TEP filed a joint consent motion, asking the Court to hold the proceedings in abeyance while the parties engaged in settlement discussions. The Court granted the motion on January 19, 2011.

On August 31, 2011, the FERC issued an order approving a settlement between TEP and the Company which became effective November 1, 2011. The settlement reduces TEP's transmission rights under the Transmission Agreement from 200 MW to 170 MW and TEP and the Company have entered into two new firm transmission capacity agreements at applicable tariff rates for a total of 40 MW. Under the terms of the settlement, the Company recorded approximately $5.4 million in transmission revenues for the period February 1, 2006 through September 30, 2011, including interest income. This adjustment was recorded in the three months ended September 30, 2011. The Company shared with its customers 25% of the transmission revenues earned before July 1, 2010, or approximately $0.7 million, through a credit to Texas fuel recoveries. As part of the settlement, the Company withdrew its appeal before the Court of Appeals.

In an ancillary proceeding, TEP filed a lawsuit in the United States District Court for the District of Arizona in December 2008, seeking reimbursement for amounts TEP paid a third party transmission provider for purchases of transmission capacity between April 2006 and May 2007, allegedly totaling approximately $1.5 million, plus accrued interest. TEP alleges that the Company was obligated to provide TEP with that transmission capacity without charge under the Transmission Agreement. As part of the settlement, this lawsuit was dismissed.

With the implementation of the settlement effective November 1, 2011, these matters between the Company and TEP were fully resolved.

10. Materially Important Transactions:

None

11. Reserved

12. Important changes during the year:

On April 21, 2011, the Company, along with the other Palo Verde Participants, was notified that the NRC had renewed the operating licenses for all three units at Palo Verde. The renewed licenses for Units 1, 2 and 3 will now expire in 2045, 2046 and 2047, respectively. For the last three quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $6.9 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $3.1 million.

On April 30, 2011, Newman Unit 5 Phase II began commercial operation. The construction of Newman Unit 5, a 278 MW combined cycle generating unit, began in July 2008 and was completed in two phases. The first phase, consisting of two 70 MW gas turbine generators, was completed in May 2009. The second phase consisted of the addition of two heat recovery steam generators and a steam turbine with a net peak period capability of 138 MW.

The Company paid a total of $27.2 million in cash dividends during the twelve months ended December 31, 2011. On March 30, 2012, the Company paid $8.8 million of quarterly dividends to shareholders.

The Company filed a request with the PUCT (Docket No. 40094), the City of El Paso, and other Texas cities on February 1, 2012 for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring the Company to show cause why its base rates for customers in the El Paso city limits should not be reduced. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for the Company's customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on the Company's rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rates finally ordered, including interest, or shall authorize the Company to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rates finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rate decisions on a “de novo” basis; therefore, the ultimate authority to set the Company's Texas electric rates is vested in the PUCT. The Company cannot predict the outcome of this proceeding. If the rate case results in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income and cash from operations. The State Office of Administrating Hearings recently established a procedural schedule that would allow for hearings in June 2012. On April 4, 2012, the Company filed a motion with the State Office of Administrating Hearings for indefinite suspension of the procedural schedule to facilitate settlement discussions. The motion was supported by all parties to the proceeding. The Administrative Law Judge granted the motion for indefinite suspension on April 6, 2012. As a result of the order, all aspects of the proceedings, including all procedural and discovery deadlines, are suspended.

Also, see response to items 1 to 11 and 13 to 14.

13. Changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period:

On January 24, 2011, the Company appointed Steve Buraczyk as Vice President of System Operations and Planning. Mr. Buraczyk served as Vice President of Power Marketing and Fuels since July 2008.

On January 24, 2011, the Company appointed John A. Whitacre as Vice President of Power Marketing and Fuels. Mr. Whitacre served as Vice President of System Operations and Planning since May 2006.

On January 24, 2011, the Company appointed Steven P. Busser as Vice President-Treasurer. Mr. Busser served as Vice President-Treasurer and Chief Risk Officer since May 2006.

On May 6, 2011, the Company appointed Hector R. Puente as Senior Vice President of Operations. Mr. Puente has served as the Company's Vice President of Transmission and Distribution since May 2006.

On June 20, 2011, the Company appointed Robert C. Doyle as Vice President of Transmission and Distribution. Mr. Doyle served as Vice President of New Mexico Affairs since February 2007.

On January 30, 2012, David W. Stevens resigned from his position as Chief Executive Officer, effective

March 2, 2012, and as a Director immediately. The Board of Directors appointed Thomas V. Shockley III to serve as the Interim Chief Executive Officer while a search is conducted to replace Mr. Stevens. Mr. Shockley has served as a member of the Company's Board of Directors since May 2010.

On April 2, 2012, Richard G. Fleager resigned from his position as Senior Vice President - Customer Care and External Affairs, effective immediately.

14. Cash management programs and events causing the proprietary capital to be less than 30 percent.

Not applicable

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	3,657,478,241	3,395,585,045
3	Construction Work in Progress (107)	200-201	167,393,912	285,086,445
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,824,872,153	3,680,671,490
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,987,897,945	1,921,791,108
6	Net Utility Plant (Enter Total of line 4 less 5)		1,836,974,208	1,758,880,382
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		172,666,608	151,908,641
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	59,014,704	44,206,978
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		113,651,904	107,701,663
14	Net Utility Plant (Enter Total of lines 6 and 13)		1,950,626,112	1,866,582,045
15	Utility Plant Adjustments (116)		1,367,339	1,669,587
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		143,495	143,495
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	1,810	1,764
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		1,119,976	2,909,334
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		175,535,725	161,512,210
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	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		176,801,006	164,566,803
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		7,443,781	4,830,604
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		187,394	272,777
38	Temporary Cash Investments (136)		576,552	74,080,685
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		57,172,272	56,581,313
41	Other Accounts Receivable (143)		2,600,756	1,340,293
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		3,015,324	2,885,128
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	1,503,621	1,582,462
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	38,685,147	34,479,028
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	33,483	70,506

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		0	0
54	Stores Expense Undistributed (163)	227	0	518
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)		7,769,698	18,081,862
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,645	4,257
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		19,589,000	16,644,000
62	Miscellaneous Current and Accrued Assets (174)		360,774	167,912
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)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		132,908,799	205,251,089
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,428,192	10,507,780
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	135,587,098	132,227,910
73	Prelim. Survey and Investigation Charges (Electric) (183)		698,646	603,099
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)		-167,899	-230,609
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	4,332,925	2,888,233
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)		20,622,570	21,496,062
82	Accumulated Deferred Income Taxes (190)	234	250,662,717	252,006,338
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		422,164,249	419,498,813
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,683,867,505	2,657,568,337

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	65,363,347	65,195,470
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		296,852,526	292,947,024
7	Other Paid-In Capital (208-211)	253	2,984,410	2,161,613
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	340,939	340,939
11	Retained Earnings (215, 215.1, 216)	118-119	905,600,092	828,660,848
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-3,851,879	-3,851,799
13	(Less) Reaquired Capital Stock (217)	250-251	424,646,957	337,638,723
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-78,988,592	-38,239,246
16	Total Proprietary Capital (lines 2 through 15)		762,972,008	808,894,248
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	193,135,000	193,135,000
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	550,000,000	550,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,338,162	3,389,719
24	Total Long-Term Debt (lines 18 through 23)		739,796,838	739,745,281
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		110,000,000	110,000,000
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		0	0
29	Accumulated Provision for Pensions and Benefits (228.3)		230,081,854	155,065,080
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		581,752	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		56,139,506	92,910,489
35	Total Other Noncurrent Liabilities (lines 26 through 34)		396,803,112	357,975,569
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		20,000,000	0
38	Accounts Payable (232)		51,703,558	41,794,961
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		5,059,590	4,945,022
42	Taxes Accrued (236)	262-263	22,266,191	22,873,744
43	Interest Accrued (237)		10,213,996	10,218,191
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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)		282,911	-159,279
48	Miscellaneous Current and Accrued Liabilities (242)		16,578,195	19,421,356
49	Obligations Under Capital Leases-Current (243)		15,288,290	6,584,997
50	Derivative Instrument Liabilities (244)		0	0
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		141,392,731	105,678,992
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		9,191,206	8,302,712
57	Accumulated Deferred Investment Tax Credits (255)	266-267	25,502,239	26,691,507
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	18,352,295	16,195,772
60	Other Regulatory Liabilities (254)	278	52,447,791	78,839,228
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		469,365,852	439,633,890
64	Accum. Deferred Income Taxes-Other (283)		68,043,433	75,611,138
65	Total Deferred Credits (lines 56 through 64)		642,902,816	645,274,247
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,683,867,505	2,657,568,337

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	918,013,291	877,215,405		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	524,749,111	509,022,684		
5	Maintenance Expenses (402)	320-323	62,091,630	56,822,998		
6	Depreciation Expense (403)	336-337	71,347,992	68,584,312		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-1,078,790	-330,388		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,668,400	6,312,115		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		1,485,415	2,216,279		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	55,561,243	54,489,075		
15	Income Taxes - Federal (409.1)	262-263	1,774,080	12,902,403		
16	- Other (409.1)	262-263	2,957,943	4,309,049		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	95,702,768	121,872,303		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	23,937,108	92,521,135		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,275,208	-1,305,668		
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)			219		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		5,692,380	8,014,140		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		801,739,856	750,387,948		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		116,273,435	126,827,457		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
918,013,291	877,215,405					2
						3
524,749,111	509,022,684					4
62,091,630	56,822,998					5
71,347,992	68,584,312					6
-1,078,790	-330,388					7
6,668,400	6,312,115					8
						9
						10
						11
1,485,415	2,216,279					12
						13
55,561,243	54,489,075					14
1,774,080	12,902,403					15
2,957,943	4,309,049					16
95,702,768	121,872,303					17
23,937,108	92,521,135					18
-1,275,208	-1,305,668					19
						20
						21
	219					22
						23
5,692,380	8,014,140					24
801,739,856	750,387,948					25
116,273,435	126,827,457					26

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)		116,273,435	126,827,457		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		265,147	471,571		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		201,333	451,420		
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)					
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-80	-226,990		
37	Interest and Dividend Income (419)		7,303,311	4,732,695		
38	Allowance for Other Funds Used During Construction (419.1)		8,160,682	10,816,188		
39	Miscellaneous Nonoperating Income (421)		7,400,632	3,657,590		
40	Gain on Disposition of Property (421.1)		112,984	297,732		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		23,041,343	19,297,366		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,801	2,471		
44	Miscellaneous Amortization (425)		302,248	512,974		
45	Donations (426.1)		1,810,642	2,004,425		
46	Life Insurance (426.2)		73,520			
47	Penalties (426.3)		112,000	88,000		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		883,015	500,446		
49	Other Deductions (426.5)		3,340,037	1,114,041		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,524,263	4,222,357		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	10,946	5,124		
53	Income Taxes-Federal (409.2)	262-263	911,788	-246,164		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	23,333,615	4,884,554		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	46,209,506	152,257		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		-85,940	-104,748		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-21,867,217	4,596,005		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		38,384,297	10,479,004		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		52,632,354	49,876,918		
63	Amort. of Debt Disc. and Expense (428)		609,303	397,085		
64	Amortization of Loss on Reaquired Debt (428.1)		873,492	873,492		
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)					
68	Other Interest Expense (431)		1,228,812	555,177		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		4,848,397	6,671,238		
70	Net Interest Charges (Total of lines 62 thru 69)		50,495,564	45,031,434		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		104,162,168	92,275,027		
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)		104,162,168	92,275,027		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		828,660,848	736,158,831
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		104,162,248	92,502,017
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				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared-Common Stock		-27,223,004	
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-27,223,004	
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		905,600,092	828,660,848
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)		905,600,092	828,660,848
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-3,851,799	(3,624,809)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-80	(226,990)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-3,851,879	(3,851,799)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	104,162,168	92,275,027
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	71,347,992	68,584,312
5	Amortization of Other	23,401,714	22,968,749
6	Amortization of Nuclear Fuel	37,161,938	31,392,216
7			
8	Deferred Income Taxes (Net)	48,889,771	34,083,465
9	Investment Tax Credit Adjustment (Net)	-1,189,268	-1,200,920
10	Net (Increase) Decrease in Receivables	-4,663,614	-1,334,730
11	Net (Increase) Decrease in Inventory	-3,787,031	1,746,142
12	Net (Increase) Decrease in Allowances Inventory	37,023	-603,626
13	Net Increase (Decrease) in Payables and Accrued Expenses	11,917,513	3,575,476
14	Net (Increase) Decrease in Other Regulatory Assets	-13,491,100	-8,878,030
15	Net Increase (Decrease) in Other Regulatory Liabilities	-16,870,576	957,150
16	(Less) Allowance for Other Funds Used During Construction	8,160,682	10,816,188
17	(Less) Undistributed Earnings from Subsidiary Companies	-80	-226,990
18	Other (provide details in footnote):	5,136,845	4,304,717
19	Unrealized (Gain) Loss on Investment in Debt Securities	-210,642	-399,483
20	Deferred Charges and Credits	568,342	2,500,893
21	Net (Increase) Decrease in Prepayments and Other	-2,537,646	-324,457
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	251,712,827	239,057,703
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-191,050,327	-187,453,606
27	Gross Additions to Nuclear Fuel	-44,923,348	-36,890,643
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-8,160,682	-10,816,188
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-227,812,993	-213,528,061
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	128,942	342,222
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-126	104,755
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Investment in Decommissioning Trust Fund (Purchases)	-95,441,195	-73,192,802
54	Investment in Decommissioning Trust Fund (Sales and Maturities)	82,925,674	61,656,140
55	Other Investing Activities	2,598,435	259,270
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-237,601,263	-224,358,476
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		
62	Preferred Stock		
63	Common Stock	-86,508,240	-33,725,756
64	Other Financing and Other Capital Lease Obligations-Proceeds	120,449,851	147,627,588
65	Exercise of Stock Options	191,700	1,378,280
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	34,133,311	115,280,112
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
74	Preferred Stock		
75	Common Stock		
76	Other Financing Activities	-1,335,817	-3,013,976
77	Financing and Capital Lease Obligations	-91,774,633	-139,920,986
78	Net Decrease in Short-Term Debt (c)		
79	Excess Tax Benefits from Long-Term Incentive Plans	1,112,240	350,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-27,223,004	
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-85,087,903	-27,304,850
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-70,976,339	-12,605,623
87			
88	Cash and Cash Equivalents at Beginning of Period	79,184,066	91,789,689
89			
90	Cash and Cash Equivalents at End of period	8,207,727	79,184,066

Schedule Page: 120 Line No.: 18 Column: a

		2011		2010
Other:				
Gain on Sale of Property	$	(110,184)	$	(299,482)
Net Losses on Equity Investments		1,358,197		122,034
Amortization of Unearned Compensation		3,831,018		2,615,223
Other Operating Activities		57,814		1,866,942
Total	$	5,136,845	$	4,304,717

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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

Note 1. Regulatory-Basis Financial Statements

The accompanying regulatory-basis financial statements are presented in accordance with the accounting requirements of the Federal Energy Regulatory Commission (the "FERC") as set forth in its applicable Uniform System of Accounts and published accounting releases which is a comprehensive basis of accounting other than generally accepted accounting principles ("GAAP") used in the 2011 Form 10-K filed by El Paso Electric Company with the Securities and Exchange Commission. Notes A through P of the regulatory-basis financial statements are from the 2011 Form 10-K and have been revised where the presentation of regulatory-basis financial statements, in accordance with requirements under the Uniform System of Accounts and published accounting releases of the FERC, result in different financial statement amounts or disclosures than under GAAP. Because many types of transactions are susceptible to varying interpretations, the amounts and classifications reported in the accompanying regulatory-basis financial statements may be subject to change at a later date upon final determination by the FERC. In the remainder of this Note 1, information contained in Notes A through P is supplemented for additional regulatory-basis disclosures.

Regulatory-Basis Financial Statements Compared to GAAP

The significant differences between the Company's regulatory-basis financial statements and those prepared in accordance with GAAP include the application of fresh-start reporting to the GAAP financial statements and the discontinuance and subsequent re-application of the provisions of FASB accounting guidance for regulated operations. In 1996, the Company adopted fresh-start reporting for its GAAP financial statements in accordance with the FASB guidance related to financial reporting by entities in reorganization under the bankruptcy code. The adoption of fresh-start reporting resulted in the creation of a new reporting entity having no retained earnings or accumulated deficit and significantly altered, compromised, or modified the Company's historical capital structure.

The Company re-implemented FASB guidance for regulated operations in 2004 for its New Mexico jurisdiction, in 2007 for its Texas jurisdiction, and in 2008 for its FERC jurisdiction. Re-application of FASB guidance for regulated operations required the Company to recognize various regulatory assets on its GAAP financial statements related to accumulated deferred income tax, coal reclamation costs, and the New Mexico and FERC jurisdictional portions of loss on re-acquired debt which had previously been expensed for GAAP reporting. During the quarter ended September 30, 2010, the Company recorded the Texas jurisdictional portion of loss on re-acquired debt as a regulatory asset for GAAP reporting as a result of the final order in PUCT Docket No. 37690 issued on July 30, 2010. Also effective with the re-application of FASB guidance for regulated operations, the Company includes AFUDC as a construction cost of electric plant in service replacing the method of calculating capitalized interest previously reported in its GAAP financial statements.

GAAP also requires earnings per share information on the income statement. GAAP requires the classification of tax assets related to the accounting guidance for "Uncertainty in Income Taxes" as a tax benefit rather than a reduction to current liabilities. GAAP also requires the classification of interest and penalties related to uncertain tax positions as tax expense rather than as interest and penalty expense.

In addition, certain items in the accompanying regulatory-basis financial statements are classified differently under FERC requirements than in the Company's GAAP financial statements. If GAAP were followed, items in the accompanying regulatory-basis financial statements would be increased (decreased) as follows (in thousands):

Line No.		2011	2010
	Assets and Other Debits (Pages 110-111)		
2	Utility plant	$ (867,705)	$ (872,723)
5	Accumulated provision for depreciation, amortization and depletion	(866,245)	(874,293)
11	Nuclear fuel under capital lease	(1,234)	(1,134)
12	Accumulated provision for amortization of nuclear fuel	867	1,264
15	Utility plant adjustments	(1,367)	(1,670)
18	Nonutility property	(143)	(143)
21	Investment in subsidiary companies	(2)	(2)
24	Other investments	(1,120)	(2,909)
28	Other special funds	(175,536)	(161,512)
67	Total current and accrued assets	8,077	(1,053)
84	Total deferred debits	(113,365)	(124,685)
	Liabilities and Other Credits (Pages 112-113)		
2	Common stock issued	89	70
6	Premium on capital stock	12,924	12,121
7	Other paid-in capital	(2,984)	(2,162)
10	Capital stock expense	(341)	(341)
11	Retained earnings	(18,426)	(17,803)
12	Unappropriated undistributed subsidiary earnings	3,852	3,852
15	Accumulated other comprehensive income	1,484	5,062
24	Total long-term debt	76,700	110,000
35	Total other noncurrent liabilities	(396,804)	(357,975)
54	Total current and accrued liabilities	43,839	25,274
65	Total deferred credits	(8,032)	(71,582)
	Statements of Income for the Year (Pages 114-117)		
2	Operating revenues	$ 0	$ 35
25	Total utility operating expenses	(74,529)	(42,099)
26	Net utility operating income	74,529	42,134
60	Net other income and deductions	(26,861)	3,815
70	Net interest charges	(5,417)	(3,109)
-	Income tax expense	53,708	51,016
-	Extraordinary item	0	10,286
78	Net income	(623)	8,328
	Statement of Retained Earnings (Pages 118-119)		
1	Balance – beginning of period	$ (17,803)	$ (25,904)
48	Total retained earnings	(18,426)	(17,803)
	Statement of Cash Flows (Pages 120-121)		
22	Net cash provided by (used in) operating activities	$ (195)	$ 292
57	Net cash provided by (used in) investing activities	195	(292)
83	Net cash provided by (used in) financing activities	0	0
	Statement of Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities (Page 122a-122b)		
9	Other comprehensive income	$ (3,579)	$ (1,619)

Statement of Cash Flows

Cash and cash equivalents and amortization of other presented on the statement of cash flows for the years ended December 31, 2011 and 2010 consist of the following (in thousands):

	2011	2010
Cash and Cash Equivalents:		
Cash (131)	$ 7,444	$ 4,830
Working funds (135)	187	273
Temporary cash investments (136)	577	74,081
Cash and cash equivalents at end of period	$ 8,208	$ 79,184
Amortization of Other:		
ARO depreciation (403.1)	$ (1,079)	$ (330)
Other utility plant (404)	6,668	6,312
Regulatory assets (407.3)	1,485	2,216
ARO liability accretion (411.10)	5,692	8,014
Miscellaneous amortization (425)	302	513
Debt expense (428)	609	397
Loss on reacquired debt (428.1)	873	874
Interest rate lock losses	361	338
RCF issuance costs	275	269
Dry cask storage amortization	2,054	2,328
Coal reclamation amortization	3,628	598
New Mexico rate case expense amortization	253	348
Texas rate case expense amortization	2,281	1,092
	$ 23,402	$ 22,969

Utility Plant Adjustments

The following table summarizes amounts reflected as Utility Plant Adjustments for the New Mexico jurisdiction as of December 31, 2011 and 2010 (in thousands):

		2011 Activity		
	December 31, 2010	Additions (Debits)	Amortization (Credits)	December 31, 2011
New Mexico (a)				
Utility Plant Adjustment	$ 17,848	$ –	$ –	$ 17,848
Accumulated Amortization	(16,178)	–	(303)	(16,481)
	$ 1,670	$ –	$ (303)	$ 1,367

(a) Represents the New Mexico jurisdictional difference between FERC regulatory-basis values and GAAP values related to Steam and Other Production assets. Established in 1998 by the Stipulation and Settlement Agreement in New Mexico Public Regulation Commission Case No. 2722. FERC account 116 was utilized to maintain the original cost concept for utility plant and is consistent with FERC's policy on plant write ups. The Company plans on amortizing this asset over the remaining lives of each respective production plant.

A. Summary of Significant Accounting Policies

General. El Paso Electric Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. El Paso Electric Company also serves a full requirements wholesale customer in Texas.

Use of Estimates. The preparation of financial statements in conformity with regulatory accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the regulatory-basis financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Basis of Presentation. The Company maintains its accounts in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, and applies such principles in its regulatory books of account to the rate treatment as ordered by each of the Company's three regulators (the Public Utility Commission of Texas (the "PUCT"), the New Mexico Public Regulation Commission (the "NMPRC") and the FERC), which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America. MiraSol Energy Services, Inc. ("MiraSol"), which began operations as a separate subsidiary in March 2001, provided energy efficiency products and discontinued these activities in 2002. The Company records its investment in MiraSol as an investment in subsidiary companies.

Comprehensive Income. Certain gains and losses that are not recognized currently in the statements of operations are reflected in the accompanying regulatory-basis balance sheet in Accumulated Other Comprehensive Income in accordance with FERC guidance for reporting comprehensive income.

Utility Plant. Utility plant is reported at original cost, less regulatory disallowances and impairments. Costs include labor, material, construction overheads and allowance for funds used during construction ("AFUDC"). Depreciation is provided on a straight-line basis at annual rates which will amortize the undepreciated cost of depreciable property over the estimated remaining lives of the assets (ranging in average from 5 to 48 years). The average composite depreciation rate utilized in 2011 and 2010 was 2.80%, and 3.21%, respectively. On April 21, 2011, the NRC notified the Palo Verde Participants that it had renewed and extended the operating licenses by 20 years for all three units at Palo Verde. The Palo Verde costs are now being depreciated on a straight-line basis over approximately 60 years and the related capital improvements at Palo Verde are being depreciated over the remaining life of the extended operating license for each unit, see Note E.

The cost of renewals and betterments are capitalized and the costs of repairs and minor replacements are charged to the appropriate operating expense accounts. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost – together with the cost of removal, less salvage – is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized.

The cost of nuclear fuel is amortized to fuel expense on a units-of-production basis. A provision for spent fuel disposal costs is charged to expense based on the funding requirements of the Department of Energy (the "DOE") for disposal cost of approximately one-tenth of one cent on each kWh generated. The Company is also amortizing its share of costs associated with on-site spent fuel storage casks at Palo Verde over the burn period of the fuel that will necessitate the use of the storage casks. See Note E.

Impairment of Long-Lived Assets. Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated undiscounted future cash flows, an impairment charge is recognized for the amount by which the carrying amount of the asset exceeds the fair value of the asset.

AFUDC and Capitalized Interest. AFUDC is determined by applying an accrual rate to the balance of certain Construction Work in Progress ("CWIP"). The FERC has promulgated procedures for the computation (a prescribed formula) of the accrual rate. The AFUDC rate used in 2011 was 8.54%. The AFUDC rate used for the first six months of 2010 was 9.01% and 8.47% thereafter. The Company capitalizes interest on nuclear fuel in accordance with the FERC Uniform System of Accounts as provided for in FASB guidance for regulated operations.

Asset Retirement Obligation. The Company complies with FERC Order No. 631, "Accounting for Financial Reporting and Rate Filing Requirements for Asset Retirement Obligations" which sets forth accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. An asset retirement obligation ("ARO") associated with long-lived assets included within the scope of FERC Order No. 631 is that for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel and legal obligations to perform an asset retirement activity even if the timing and/or settlement are conditioned on a future event that may or may not be within the control of an entity. See Note F. Under the order, these liabilities are recognized as incurred if a reasonable estimate of fair value can be established and are capitalized as part of the cost of the related tangible long-lived assets. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense).

Cash and Cash Equivalents. All temporary cash investments with an original maturity of three months or less are considered cash equivalents.

Investments. The Company's marketable securities, included in Other Special Funds in the regulatory-basis balance sheets, are reported at fair value and consist of cash, equity securities and municipal, federal and corporate bonds in trust funds established for decommissioning of its interest in Palo Verde. Such marketable securities are classified as "available-for-sale" securities and, as such, unrealized gains and losses are included in Accumulated Other Comprehensive Income. However, if declines in fair value of marketable securities below original cost basis are determined to be other than temporary, then the declines are reported as losses in the regulatory-basis statement of operations and a new cost basis is established for the affected securities at fair value. Gains and losses are determined using the cost of the security based on the specific identification basis. See Note O.

Derivative Accounting. Accounting for derivative instruments and hedging activities requires the recognition of derivatives as either assets or liabilities in the regulatory-basis balance sheet with measurement of those instruments at fair value. Any changes in the fair value of these instruments are recorded in earnings or other comprehensive income. See Note O.

Inventories. Inventories, primarily parts, materials, supplies, fuel oil and natural gas are stated at average cost not to exceed recoverable cost.

Operating Revenues Net of Energy Expenses. The Company accrues revenues for services rendered, including unbilled electric service revenues. Energy expenses are stated at actual cost incurred. The Company's Texas retail customers are billed under base rates and a fixed fuel factor approved by the PUCT. The Company's New Mexico retail customers and its sales for resale customer are billed under base rates and a fuel adjustment clause which is adjusted monthly, as approved by the NMPRC and the FERC. The Company's recovery of energy expenses is subject to periodic reconciliations of actual energy expenses incurred to actual fuel revenues collected. The difference between energy expenses incurred and fuel revenues charged to customers is reflected in the accompanying regulatory-basis balance sheets in Other Regulatory Assets and Other Regulatory Liabilities, as appropriate. See Note C.

Revenues. Revenues related to the sale of electricity are generally recorded when service is rendered or electricity is delivered to customers. The billing of electricity sales to retail customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. Unbilled revenues are estimated based on monthly generation volumes and by applying an average revenue/kWh to the number of estimated kWhs delivered but not billed. Accrued Utility Revenues include accrued unbilled revenues of $19.6 million and $16.6 million at December 31, 2011 and 2010, respectively. The Company presents revenues net of sales taxes in its regulatory-basis statements of operations.

Allowance for Doubtful Accounts. The allowance for doubtful accounts represents the Company's estimate of existing accounts receivable that will ultimately be uncollectible. The allowance is calculated by applying estimated write-off factors to various classes of outstanding receivables. The write-off factors used to estimate uncollectible accounts are based upon consideration of both historical collections experience and management's best estimate of future collections success given the existing collections environment. Additions, deductions and balances for allowance for doubtful accounts for 2011 and 2010 are as follows (in thousands):

	2011	2010
Balance at beginning of year	$ 2,885	$ 1,191
Additions:		
Charged to costs and expense	6,209	4,756
Recovery of previous write-offs	2,034	852
Uncollectible receivables written off	8,113	3,914
Balance at end of year	$ 3,015	$ 2,885

Income Taxes. The Company accounts for federal and state income taxes under the asset and liability method of accounting for income taxes. Deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. The Company recognizes tax assets and liabilities for uncertain tax positions in accordance with the recognition and measurement criteria of FASB guidance for uncertainty in income taxes as modified by FERC Docket AI07-2-000. See Note J.

Stock-Based Compensation. The Company has a stock-based long-term incentive plan. The Company is required under FASB guidance to measure the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. Such costs are recognized over the period during which an employee is required to provide service in exchange for the award (the "requisite service period") which typically is the vesting period. Compensation cost is not recognized for anticipated forfeitures prior to vesting of equity instruments. See Note G.

Pension and Postretirement Benefit Accounting. For a full discussion of the Company's accounting policies for its employee benefits. See Note M.

Reclassification. Certain amounts in the regulatory-basis financial statements for 2010 have been reclassified to conform with the 2011 presentation.

B. New Accounting Standards

In January 2010, the FASB issued new guidance to improve disclosure requirements related to fair value measurements and disclosures. The new requirements include: (i) disclosure of significant transfers in and out of Level 1 and Level 2 fair value measurements and the reasons for the transfers; and (ii) disclosure in the reconciliation for Level 3 fair value measurements of information about purchases, sales, issuances and settlements on a gross basis. The new guidance also clarifies existing disclosures and requires: (i) an entity to provide fair value measurement disclosures for each class of assets and liabilities and (ii) disclosures about inputs and valuation techniques. The provisions of this new guidance were adopted in the first quarter of 2010 except for the reconciliation for the Level 3 fair value measurements on a gross basis which was adopted during the first quarter of 2011. This guidance requires additional disclosure on fair value measurements but did not impact the Company's regulatory-basis financial statements.

C. Regulation

General

The rates and services of the Company are regulated by incorporated municipalities in Texas, the PUCT, the NMPRC, and the FERC. The PUCT and the NMPRC have jurisdiction to review municipal orders, ordinances and utility agreements regarding rates and services within their respective states and over certain other activities of the Company. The FERC has jurisdiction over the Company's wholesale transactions and compliance with federally-mandated reliability standards. The decisions of the PUCT, NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

2009 Texas Retail Rate Case. On December 9, 2009, the Company filed an application with the PUCT for authority to change rates, to reconcile fuel costs, to establish formula-based fuel factors and to establish an energy efficiency cost-recovery factor. This case was assigned PUCT Docket No. 37690. The filing included a base rate increase which was based upon an adjusted test year ended June 30, 2009.

On July 30, 2010, the PUCT approved a settlement in the 2009 Texas retail rate case in PUCT Docket No. 37690. The settlement called for an annual non-fuel base rate increase of $17.15 million effective for usage beginning July 1, 2010. The new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. This increase was partially offset by the provision that, consistent with a prior rate agreement, effective July 1, 2010, the Company shares 90% of off-system sales margins with customers and retains 10% of such margins. Previously, the Company retained 75% of off-system sales margins. All additions to electric plant in service since June 30, 1993 through June 30, 2009 were deemed to be reasonable and necessary with the exception of one small addition. The Company's new customer information system completed in April 2010 was also included in base rates with a 10-year amortization. The settlement provided for the reconciliation of fuel costs incurred through June 30, 2009 except for the recovery of final Four Corners' coal mine reclamation costs. The fuel reconciliation (Docket No. 38361, discussed below) was bifurcated from the rate case to allow for litigation of the final coal mine reclamation costs. The PUCT also approved the use of a formula-based fuel factor which provides for more timely recovery of fuel costs. The PUCT approved a $19.7 million or 11% reduction in the Company's fixed fuel factor as the initial rate under the approved fuel factor formula. The PUCT also approved an energy efficiency cost-recovery factor that includes the recovery of deferred energy efficiency costs over a three-year period.

2012 Texas Retail Rate Case. The Company filed a request with the PUCT (Docket No. 40094), the City of El Paso, and other Texas cities on February 1, 2012 for a $26.3 million increase in rates charged to customers in Texas. The rate filing was made in response to a resolution adopted by the El Paso City Council requiring the Company to show cause why its base rates for customers in the El Paso city limits should not be reduced. The rate filing used a historical test year ended September 30, 2011, adjusted for known and measurable items, and a return on equity of 10.6%. The filing at the PUCT also includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011.

On November 15, 2011, the El Paso City Council adopted a resolution which established current rates as temporary rates for the Company's customers residing within the city limits of El Paso. Temporary rates will be effective from November 15, 2011 until a final determination is made by the PUCT on the Company's rates in the rate proceeding initiated by the City's Show Cause Order. Upon a final determination by the PUCT, the PUCT may order a refund to customers of money collected in excess of the rates finally ordered, including interest, or shall authorize the Company to surcharge bills to recover the amount, including interest, by which the money collected under the temporary rates is less than the money that would have been collected under the rates finally ordered. The rates proposed by the Company in the Texas rate case included increases for some customer classes and decreases for other customer classes. As a result, consistent implementation of the proposed rates may require the PUCT to reflect the differences in temporary and final rates from November 15, 2011 for each affected class.

While cities in Texas have jurisdiction over rates in their city limits, the PUCT has appellate authority over city rate decisions on a "de novo" basis; therefore, the ultimate authority to set the Company's Texas electric rates is vested in the PUCT. The Company cannot predict the outcome of this proceeding. If the rate case results in implementing lower rates, the resulting lower rates would have a negative impact on the Company's revenues, net income and cash from operations. The State Office of Administrating Hearings recently established a procedural schedule that would allow for hearings in June 2012. On April 4, 2012, the Company filed a motion with the State Office of Administrating Hearings for indefinite suspension of the procedural schedule to facilitate settlement discussions. The motion was supported by all parties to the proceeding. The Administrative Law Judge granted the motion for indefinite suspension on April 6, 2012. As a result of the order, all aspects of the proceedings, including all procedural and discovery deadlines, are suspended.

Fuel Reconciliation Case (Severed from 2009 Rate Case). Pursuant to the stipulation in the Company's 2009 rate case, the PUCT established Docket No. 38361 to address the one fuel reconciliation issue not settled by the parties. That single issue was a determination of the proper amount of the Four Corners' coal mine final reclamation costs to be recovered from the Company's Texas retail customers. The hearing on the merits of the case was held on August 11, 2010. On November 23, 2010 the Administrative Law Judge (the "ALJ") issued the Proposal for Decision which approved the Company's request. The PUCT issued a final order approving the Proposal for Decision on January 27, 2011.

Fuel and Purchased Power Costs. The Company's actual fuel costs, including purchased power energy costs, are recoverable from its customers. The PUCT has adopted a fuel cost recovery rule ("Texas Fuel Rule") that allows the Company to seek periodic adjustments to its fixed fuel factor. The Company received approval on July 30, 2010 in PUCT Docket No. 37690 (discussed above), to implement a formula to determine its fuel factor which adjusts natural gas and purchased power to reflect natural gas futures prices. The Company can seek to revise its fixed fuel factor based upon the approved formula at least four months after its last revision except in the month of December. The Texas Fuel Rule requires the Company to request to refund fuel costs in any month when the over-recovery balance exceeds a threshold material amount and it expects fuel costs to continue to be materially over-recovered. The Texas Fuel Rule also permits the Company to seek to surcharge fuel under-recoveries in any month the balance exceeds a threshold material amount and it expects fuel cost recovery to continue to be materially under-recovered. Fuel over and under-recoveries are considered material when they exceed 4% of the previous twelve months' fuel costs. All such fuel revenue and expense activities are subject to periodic final review by the PUCT in fuel reconciliation proceedings.

The Company has filed the following petitions with the PUCT to refund recent fuel cost over-recoveries, due primarily to fluctuations in natural gas markets and consumption levels. The table summarizes the docket number assigned by the PUCT, the dates the Company filed the petitions and the dates a final order was issued by the PUCT approving the refunds to customers. The fuel cost over-recovery periods represent the months in which the over-recoveries took place and the refund periods represent the billing month(s) in which customers received the refund amounts shown, including interest:

Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount (In thousands)
37788	December 17, 2009	February 11, 2010	September – November 2009	February 2010	$ 11,800
38253	May 12, 2010	July 15, 2010	December 2009 – March 2010	July – August 2010	11,100
38802	October 20, 2010	December 16, 2010	April – September 2010	December 2010	12,800
39159	February 18, 2011	May 3, 2011	October – December 2010	April 2011	11,800

The Company has filed the following petitions with the PUCT to revise its fixed fuel factor pursuant to the fuel factor formula authorized in PUCT Docket No. 37690:

Docket No.	Date Filed	Date Approved	Increase (Decrease) in Fuel Factor	Effective Billing Month
38895	November 23, 2010	January 6, 2011	(14.7)%	January 2011
39599	July 15, 2011	August 30, 2011	9.4%	August 2011

As noted above, the rate filing filed with the PUCT on February 1, 2012 (Docket No. 40094), includes a request to reconcile $356.5 million of fuel expense for the period July 1, 2009 through September 30, 2011. However, this filing does not request a change in the fixed fuel factor.

Application for Approval to Revise Energy Efficiency Cost Recovery Factor for 2012. On May 2, 2011, the Company filed with the PUCT an application for approval to revise its energy efficiency cost recovery factor ("EECRF"), which was assigned PUCT Docket No. 39376. A unanimous settlement resolving all issues was filed with the PUCT on July 15, 2011. The settlement allows the Company to recover $8.3 million and supports the Company's request to revise its demand and energy goals and EECRF cost caps as well as the Company's request to increase its 2012 EECRF, effective beginning with the first billing cycle of its January 2012 billing month. A final order in the case was issued August 23, 2011, approving the settlement.

Petition for Approval to Revise Military Base Discount Recovery Factor. On July 14, 2011, the Company filed with the PUCT a petition requesting approval to revise its Military Base Discount Recovery Factor ("MBDRF") tariff to account for under-recovery of discount charges during 2010 and for 2011 discounts. A final order was issued January 12, 2012 revising the MBDRF to 0.936% and allowing $3.9 million dollars of under-recovered discount charges to begin February 1, 2012.

Application for a Certificate of Convenience and Necessity ("CCN") for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned PUCT Docket No. 38717. A unanimous settlement to approve the CCN was filed on March 2, 2011, and a final order granting the CCN was approved on April 8, 2011.

Project to Investigate Early February 2011 Outages and Curtailments. On February 8, 2011, the PUCT opened Project No. 39134, *Investigation into Power Outages in El Paso Electric's Service Territory*. In this project, the PUCT is investigating the Company's power plant outages and customer curtailments that occurred February 2-4, 2011, as a result of the extreme cold weather in the El Paso area. The PUCT Staff conducted discovery in the investigation. On February 14, 2011, the Company also filed a report on this weather event. On May 13, 2011, the PUCT Staff issued a report stating that, as of then, it had not identified violations by the Company of the Texas electric utility regulatory statute or PUCT rules. The report also stated that the PUCT Staff would continue to monitor the extreme cold weather event results and subsequent forthcoming information as the Company and other regulatory agencies complete their ongoing investigations.

On February 15, 2011, the City Council of El Paso passed a motion that, upon the conclusion of other hearings and investigations into the extreme cold weather event, the Mayor would call for Special City Council meetings or public hearings to evaluate how the three utility companies operating within the city, including the Company, performed during the extreme weather event. The El Paso City Council retained a consultant to assess the Company's activities during the weather event and the Company's subsequent actions to prevent outages during a similar future event. The El Paso City Council's consultant presented the following three recommendations to the El Paso City Council on December 20, 2011: (i) request the Company to prepare and present an updated reliability study; (ii) request the Company and El Paso Water Utilities to present their coordinated plans for power and water supply to critical loads during severe weather events; and (iii) request the Company to file an updated emergency operations plan with both the PUCT and the El Paso City Council which will be completed in 2012. The El Paso City Council unanimously passed a motion to approve the three recommendations. At the January 10, 2012 El Paso City Council Meeting, the Company presented information requested in recommendations (i) and (ii) above.

Application of El Paso Electric Company to Amend its Certificate of Convenience and Necessity for Five Solar Power Generation Projects. On December 9, 2011, the Company filed a petition seeking a CCN to construct five solar powered generation projects, totaling approximately 2.6MW, at four locations within the City of El Paso and one location in the Town of Van Horn. This case was assigned PUCT Docket No. 39973 and is still pending.

New Mexico Regulatory Matters

2009 New Mexico Stipulation. On May 29, 2009, the Company filed a general rate case using a test year ended December 31, 2008. The 2009 rate case was docketed as NMPRC Case No. 09-00171-UT. A comprehensive unopposed stipulation (the "2009 New Mexico Stipulation") was reached in this general rate case and filed on October 8, 2009. The 2009 New Mexico Stipulation provided for an increase in New Mexico jurisdictional non-fuel and purchased power base rate revenues of $5.5 million. The new rate structure resulted in net increases in base rates during the peak summer season of May through October and net decreases in base rates during November through April. The 2009 New Mexico Stipulation provided for the revision of depreciation rates for the Palo Verde nuclear generating plant to reflect a 20-year life extension and a revision of depreciation rates for other plant in service. The 2009 New Mexico Stipulation also provided for the continuation of the Company's Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") without conditions or variance. In addition, it modified the market pricing of capacity and energy provided by Palo Verde Unit 3 using a methodology based upon a previous purchased power contract with Credit Suisse Energy, LLC. On December 10, 2009, the NMPRC issued a final order conditionally approving and clarifying the unopposed stipulation, and the stipulated rates went into effect with January 2010 bills.

Application for Approval to Recover Regulatory Disincentives and Incentives. On August 31, 2010, the Company filed an application for approval of its proposed rate design methodology to recover regulatory disincentives and incentives associated with the Company's energy efficiency and load management programs in New Mexico. On March 18, 2011, the Company entered into an uncontested stipulation which would provide for a rate per kWh of energy efficiency savings that would be recovered through the efficient use of energy rider. A hearing on the uncontested stipulation was held on April 26, 2011 and briefs were filed on September 26, 2011. A final order was issued on November 22, 2011 in which the NMPRC did not adopt the unopposed stipulation, but modified the structure of the energy rider to reduce the return to two percent and made the mechanism temporary. The Company filed a Notice of Appeal with the Supreme Court of the State of New Mexico on January 20, 2012 on the grounds that the NMPRC's decision is arbitrary and without substantial evidence.

Application for a CCN for Rio Grande Unit 9. On September 30, 2010, the Company filed a petition seeking a CCN to construct an 87 MW natural gas-fired combustion turbine unit at the Company's existing Rio Grande Generating Station in the City of Sunland Park in southeast New Mexico. This case was assigned NMPRC Case No. 10-00301-UT. On April 13, 2011 an unopposed stipulation was filed in this case seeking approval of a CCN for the Company to construct, own and operate the 87 MW generating unit. A final order on this case approving the CCN was issued on June 23, 2011.

Application for Approval of 2011 New and Modified Energy Efficiency Programs. On February 15, 2011, the Company filed its Application for Approval of New and Modified Energy Efficiency Programs for 2011 with the NMPRC. On June 22, 2011, parties to this case entered into a partial stipulation, agreeing on all issues, except for a military base free-ridership issue. On June 24, 2011, the New Mexico Attorney General filed a statement in opposition to the proposed partial stipulation. On January 25, 2012, a hearing examiner issued a recommended decision modifying the stipulation by approving the Energy Efficiency programs and budgets with the exception of the Commercial Lighting Program, approving the adder for 2011 but not for 2012 or 2013 and excluding the Military Research & Development Class from participation in the rate rider and reducing the Company's required saving goals accordingly. On February 2, 2012, the Company filed certain exceptions to the recommended decision and requested an interim order related to this matter. The NMPRC issued a final order approving the partial stipulation and rejecting the Company’s exceptions on February 21, 2012. On March 5, 2012, the Company filed an unopposed motion to immediately implement the approved programs and to initiate further proceedings to allow the parties to supplement the record to support the stipulated adders for 2012 and 2013. On March 20, 2012 the NMPRC issued an order granting the unopposed motion.

2011 Renewable Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2011, the Company filed its Application for Approval of its 2011 Renewable Procurement Plan with the NMPRC, which was assigned NMPRC Case No. 11-00263-UT. The filing identified renewable resources intended to meet the Company's Renewable Portfolio Standard ("RPS") requirements in 2012 and 2013. The renewable resources in the 2011 Renewable Procurement Plan, which were previously approved by the NMPRC, will allow the Company to meet the full RPS requirement of 10% of the Company's jurisdictional retail energy sales for 2012 and 2013. The Company's 2011 Renewable Procurement Plan also addresses the diversity targets in 2012 and 2013 required by NMPRC Rule 572 and demonstrates that the Company will meet those targets. The 2011 Renewable Procurement Plan also demonstrates that the Company will meet its solar diversity target in 2012 and comply with the terms of a previously-approved variance for 2011. A hearing in this case was held on October 13, 2011. A final order was issued on December 15, 2011 approving the 2011 Renewable Procurement Plan.

Investigation into Rates for Church Customers. On July 12, 2011, the NMPRC initiated an investigation into the rates the Company charges its church customers which were approved in Case No. 09-00171-UT. The investigation, Case No. 11-00276-UT, was ordered to determine whether the Company's rates to its church customers are unjust and unreasonable and should be revised. The Company filed a response on August 1, 2011. A mediation conference was held on August 23, 2011 which resulted in an Unopposed Joint Stipulation, filed on October 14, 2011. The stipulation limits billing impacts to religious organizations that take service under the Company's standard small commercial rate. The stipulation was approved by the NMPRC on October 27, 2011.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the NMPRC in Case No. 11-00349-UT to amend and restate the Company's $200 million revolving credit facility ("RCF"), which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and Rio Grande Resources Trust ("RGRT") amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016.

On March 29, 2012, the Company and The Bank of New York Mellon Trust Company, N.A., as trustee of the Rio Grande Resources Trust, entered into the Incremental Facility Assumption Agreement (the "Assumption Agreement") related to the RCF discussed above with JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, Union Bank, N.A., as syndication agent, and various lending banks party thereto. The Assumption Agreement provides for the Company's exercise in full of the accordion feature provided for under the RCF, increasing the aggregate unsecured borrowing available from $200 million to $300 million. In addition, the Assumption Agreement reflects the addition of a new lender under the RCF. No other material modifications have been made to the terms and conditions of the RCF.

Federal Regulatory Matters

Transmission Dispute with Tucson Electric Power Company ("TEP"). In January 2006, the Company filed a complaint with the FERC to interpret the terms of a Power Exchange and Transmission Agreement (the "Transmission Agreement") entered into with TEP in 1982. TEP filed a complaint with the FERC one day later raising virtually identical issues. TEP claimed that, under the Transmission Agreement, it was entitled to up to 400 MW of firm transmission rights on the Company's transmission system that would enable it to transmit power from the Luna Energy Facility ("LEF") located near Deming, New Mexico to Springerville or Greenlee in Arizona. The Company asserted that TEP's rights under the Transmission Agreement do not include transmission rights necessary to transmit such power as contemplated by TEP and that TEP must acquire any such rights in the open market from the Company at applicable tariff rates or from other transmission providers. On April 24, 2006, the FERC ruled in the Company's favor, finding that TEP does not have transmission rights under the Transmission Agreement to transmit power from the LEF to Arizona. The ruling was based on written evidence presented and without an evidentiary hearing. TEP's request for a rehearing of the FERC's decision was granted in part and denied in part in an order issued October 4, 2006, and hearings on the disputed issues were held before an administrative law judge. In the initial decision dated September 6, 2007, the administrative law judge found that the Transmission Agreement allows TEP to transmit power from the LEF to Arizona but limits that transmission to 200 MW on any segment of the circuit and to non-firm service on the segment from Luna to Greenlee. The Company and TEP filed exceptions to the initial decision.

On November 13, 2008, the FERC issued an order on the initial decision finding that the transmission rights given to TEP in the Transmission Agreement are firm and are not restricted for transmission of power from Springerville as the receipt point to Greenlee as the delivery point. Therefore, pursuant to the order, TEP can use its transmission rights granted under the Transmission Agreement to transmit power from the LEF to either Springerville or Greenlee so long as it transmits no more than 200 MW over all segments at any one time.

The FERC also ordered that the Company refund to TEP all sums with interest that TEP had paid it for transmission under the applicable transmission service agreements since February 2006 for service relating to the LEF. On December 3, 2008, the Company refunded $9.7 million to TEP. The Company had established a reserve for the rate refund of approximately $7.2 million as of September 30, 2008, resulting in a pre-tax charge to earnings of approximately $2.5 million in 2008. The Company also paid TEP interest on the refunded balance of approximately $0.9 million, which was also charged to earnings in 2008. The Company filed a request for rehearing of the FERC's decision on December 15, 2008, seeking reversal of the order on the merits and a return of any refunds made in the interim, as well as compensation for all service that the Company may provide to TEP from the LEF over the Company's transmission system on a going forward basis. On July 7, 2010, the FERC denied the Company's request for rehearing. On

July 23, 2010, the Company filed a petition for review in the United States Court of Appeals for the District of Columbia Circuit (the "Court of Appeals") and on August 18, 2010, TEP filed a motion to intervene in the proceeding. On January 14, 2011, the Company and TEP filed a joint consent motion, asking the Court to hold the proceedings in abeyance while the parties engaged in settlement discussions. The Court granted the motion on January 19, 2011.

On August 31, 2011, the FERC issued an order approving a settlement between TEP and the Company that became effective November 1, 2011. The settlement reduces TEP's transmission rights under the Transmission Agreement from 200 MW to 170 MW, and TEP and the Company have entered into two new firm transmission capacity agreements at applicable tariff rates for a total of 40 MW. Those two new service agreements were entered into and became effective November 1, 2011. Also under the terms of the settlement, TEP made a lump-sum cash payment to the Company of approximately $5.4 million for the period February 1, 2006 through September 30, 2011, including interest income. This adjustment was recorded in the three months ended September 30, 2011. The Company shared with its customers 25% of the transmission revenues earned before July 1, 2010, or approximately $0.7 million, through a credit to Texas fuel recoveries. As part of the settlement, the Company withdrew its appeal before the Court of Appeals.

In an ancillary proceeding, TEP filed a lawsuit in the United States District Court for the District of Arizona in December 2008, seeking reimbursement for amounts TEP paid a third party transmission provider for purchases of transmission capacity between April 2006 and May 2007, allegedly totaling approximately $1.5 million, plus accrued interest. TEP alleges that the Company was obligated to provide TEP with that transmission capacity without charge under the Transmission Agreement. As part of the settlement, this lawsuit was dismissed.

With the implementation of the settlement effective November 1, 2011, these matters between the Company and TEP were fully resolved.

Inquiry into Early February 2011 Outages and Curtailments. On February 14, 2011, the FERC directed its staff to initiate an inquiry into power plant outages and customer curtailments by power generators and gas suppliers in the Southwestern United States, including the Company, in early February 2011, as a result of the extreme cold weather. The FERC specifically stated that its inquiry is not an enforcement investigation. On August 16, 2011, the FERC released its staff report, Docket No. AD11-9-000, where it made recommendations to help prevent a recurrence of such outages in the future, and making no finding of violations or assessments of penalties.

Revolving Credit Facility and Guarantee of Debt. On October 13, 2011, the Company received final approval from the FERC in Docket No. ES11-43-000 to amend and restate the Company's $200 million RCF, which includes an option, subject to lender's approval, to expand the size to $300 million, and to incrementally issue up to $300 million of long-term debt as and when needed. Obtaining the ability to issue up to $300 million of new long-term debt, from time to time, provides the Company with the flexibility to access the debt capital markets when needed and when conditions are favorable.

On November 15, 2011, the Company and RGRT amended and restated the $200 million unsecured RCF with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. The amended and restated RCF reduces borrowing costs and extends the maturity from September 2014 to September 2016.

On March 29, 2012, the Company and The Bank of New York Mellon Trust Company, N.A., as trustee of the Rio Grande Resources Trust, entered into the Incremental Facility Assumption Agreement (the "Assumption Agreement") related to the RCF discussed above with JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, Union Bank, N.A., as syndication agent, and various lending banks party thereto. The Assumption Agreement provides for the Company's exercise in full of the accordion feature provided for under the RCF, increasing the aggregate unsecured borrowing available from $200 million to $300 million. In addition, the Assumption Agreement reflects the addition of a new lender under the RCF. No other material modifications have been made to the terms and conditions of the RCF.

Department of Energy. The DOE regulates the Company's exports of power to the Comisión Federal de Electricidad in Mexico pursuant to a license granted by the DOE and a presidential permit.

The DOE is authorized to assess operators of nuclear generating facilities a share of the costs of decommissioning the DOE's uranium enrichment facilities and for the ultimate costs of disposal of spent nuclear fuel. See Note E for discussion of spent fuel storage and disposal costs.

Nuclear Regulatory Commission ("NRC"). The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards. The NRC also has the authority to grant license extensions pursuant to the Atomic Energy Act of 1954, as amended.

Sales for Resale

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract with a two-year notice to terminate provision. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

D. Regulatory Assets and Liabilities

The Company's operations are regulated by the PUCT, the NMPRC and the FERC. Regulatory assets represent probable future recovery of previously incurred costs, which will be collected from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Company's regulatory-basis balance sheets are presented below (in thousands):

	Amortization Period Ends	December 31, 2011	December 31, 2010
Regulatory assets			
Regulatory tax assets (a)	(b)	$ 98,123	$ 102,238
Final coal reclamation (a)	July 2016	6,655	10,282
Nuclear fuel postload daily financing charge	(c)	3,680	2,166
Texas energy efficiency	(d)	4,497	5,460
Texas 2009 rate case costs (e)	June 2012	1,146	3,298
Texas 2012 rate case costs	(f)	648	—
Texas military base discount and recovery factor	(g)	2,526	761
New Mexico 2009 rate case procurement plan costs (e)	December 2011	—	232
New Mexico procurement plan costs	(f)	139	122
New Mexico 2009 rate case renewable energy credits (e)	December 2011	—	1,139
New Mexico renewable energy credits	(f)	2,884	930
New Mexico 2009 rate case costs (e)	December 2012	253	506
New Mexico 2010 FPPCAC audit	(f)	427	—
New Mexico Palo Verde deferred depreciation	(b)	5,176	4,773
New Mexico energy efficiency	(d)	303	321
Undercollection of fuel revenues	(h)	9,130	—
Total regulatory assets		$ 135,587	$ 132,228
Regulatory liabilities			
Regulatory tax liabilities (a)	(b)	$ 50,343	$ 59,863
Overcollection of fuel revenues	(h)	2,105	18,976
Total regulatory liabilities		$ 52,448	$ 78,839

(a) No specific return on investment is required since related assets and liabilities, including accumulated deferred income taxes and reclamation liability, offset.

(b) The amortization period for this asset is based upon the life of the associated assets.

(c) This item is recovered through fuel recovery mechanisms.

(d) This asset is recovered through an annual recovery factor.

(e) This item is included in rate base which earns a return on investment.

(f) Amortization period is anticipated to be established in next general rate case.

(g) This item represents the net asset related to the military discount which is recovered from non-military customers through a recovery factor.

(h) Recovery or refund is through fuel adjustment mechanisms in each jurisdiction.

E. Utility Plant, Palo Verde and Other Jointly-Owned Utility Plant

The table below presents the balance of each major class of depreciable assets at December 31, 2011 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear production	$ 1,711,994	$ (1,171,168)	$ 540,826
Steam and other	558,769	(234,527)	324,242
Total production	2,270,763	(1,405,695)	865,068
Transmission	342,702	(190,847)	151,855
Distribution	832,955	(275,712)	557,243
General	147,641	(83,541)	64,100
Intangible	63,417	(32,103)	31,314
Total	$ 3,657,478	$ (1,987,898)	$ 1,669,580

Amortization of intangible plant (software) is provided on a straight-line basis over the estimated useful life of the asset (ranging from 5 to 10 years). The table below presents the actual and estimated amortization expense for intangible plant for the previous three years and for the next five years (in thousands):

2009	$ 4,542
2010	6,312
2011	6,668
2012 (estimated)	6,124
2013 (estimated)	5,403
2014 (estimated)	4,292
2015 (estimated)	3,542
2016 (estimated)	3,045

The Company owns a 15.8% interest in each of the three nuclear generating units and common facilities at Palo Verde, in Wintersburg, Arizona. The Palo Verde Participants include the Company and six other utilities: Arizona Public Service Company ("APS"), Southern California Edison Company ("SCE"), Public Service Company of New Mexico ("PNM"), Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power.

Other jointly-owned utility plant includes a 7% interest in Units 4 and 5 at Four Corners Generating Station ("Four Corners") and certain other transmission facilities. A summary of the Company's investment in jointly-owned utility plant, excluding fuel inventories, at December 31, 2011 and 2010 is as follows (in thousands):

	December 31, 2011		December 31, 2010	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$ 1,711,994	$ 169,590	$ 1,721,885	$ 167,034
Accumulated depreciation	(1,171,168)	(123,152)	(1,163,013)	(118,257)
Construction work in progress	53,822	1,634	48,703	1,940
Total	$ 594,648	$ 48,072	$ 607,575	$ 50,717

Palo Verde

The operation of Palo Verde and the relationship among the Palo Verde Participants is governed by the Arizona Nuclear Power Project Participation Agreement (the "ANPP Participation Agreement"). APS serves as operating agent for Palo Verde, and under the ANPP Participation Agreement, the Company has limited ability to influence operations and costs at Palo Verde. Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units, and each participant is required to fund its share of fuel, other operations, maintenance and capital costs. The Company's share of direct expenses in Palo Verde and other jointly-owned utility plants is reflected in fuel expense, other operations expense, maintenance expense, miscellaneous other deductions, and taxes other than income taxes in the Company's regulatory-basis statements of operations. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant. Because it is impracticable to predict defaulting participants, the Company cannot estimate the maximum potential amount of future payment, if any, which could be required under this provision.

NRC. The NRC regulates the operation of all commercial nuclear power reactors in the United States, including Palo Verde. The NRC periodically conducts inspections of nuclear facilities and monitors performance indicators to enable the agency to arrive at objective conclusions about a licensee's safety performance.

License Extension. On April 21, 2011, the Company, along with the other Palo Verde Participants, was notified that the NRC had renewed the operating licenses for all three units at Palo Verde. The renewed licenses for Units 1, 2 and 3 will now expire in 2045, 2046 and 2047, respectively. For the last three quarters of 2011 combined, the extension of the operating licenses had the effect of reducing depreciation and amortization expense by approximately $6.9 million and reducing the accretion expense on the Palo Verde asset retirement obligation by approximately $3.1 million.

Decommissioning. Pursuant to the ANPP Participation Agreement and federal law, the Company must fund its share of the estimated costs to decommission Palo Verde Units 1, 2 and 3, including the Common Facilities, through the term of their respective operating licenses. The Company is required to maintain a minimum accumulation and a minimum funding level in its decommissioning account at the end of each annual reporting period during the life of the plant. The Company has established external trusts with an independent trustee, which enables the Company to record a current deduction for federal income tax purposes for most of the amounts funded. At December 31, 2011, the Company's decommissioning trust fund had a balance of $168.0 million, and the Company was above its minimum funding level. The Company will continue to monitor the status of its decommissioning funds and adjust its deposits, if necessary, to remain at or above its minimum accumulation requirements in the future.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. On March 30, 2011, the Palo Verde Participants approved the 2010 Palo Verde decommissioning study (the "2010 Study"). The 2010 Study reflects the increase in the license life from 40 years to 60 years. The 2010 Study estimated that the Company must fund approximately $357.4 million (stated in 2010 dollars) to cover its share of decommissioning costs which was an increase in decommissioning costs of $33.0 million (stated in 2010 dollars) from the 2007 Palo Verde decommissioning study (the "2007 Study"). The net effect of these changes lowered the asset retirement obligation by $41.7 million and will lower annual expenses in the future. Although the 2010 Study was based on the latest available information, there can be no assurance that decommissioning cost estimates will not increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste are subject to significant uncertainty. See "Spent Fuel Storage" and "Disposal of Low-Level Radioactive Waste" below.

Spent Fuel Storage. The original spent fuel storage facilities at Palo Verde had sufficient capacity to store all fuel discharged from normal operation of all three Palo Verde units through 2003. Alternative on-site storage facilities and casks have been constructed to supplement the original facilities. In March 2003, APS began removing spent fuel from the original facilities as necessary, and placing it in special storage casks which will be stored at the on-site facilities until accepted by the DOE for permanent disposal. The 2010 Study assumed that costs to store fuel on-site will become the responsibility of the DOE after 2057. APS believes that spent fuel storage or disposal methods will be available to allow each Palo Verde unit to continue to operate through the current term of its operating license.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the DOE is legally obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive waste generated by all domestic power reactors. In accordance with the Waste Act, the DOE entered into a spent nuclear fuel contract with the Company and all other Palo Verde Participants. The DOE has previously reported that its spent nuclear fuel disposal facilities would not be in operation in the near future. In November 1997, the United States Court of Appeals for the District of Columbia Circuit issued a decision preventing the DOE from excusing its own delay but refused to order the DOE to begin accepting spent nuclear fuel. The Company cannot predict when spent fuel shipments to the DOE will commence.

The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde that the Company believes are the responsibility of the DOE. These costs are assigned to fuel requiring the additional on-site storage and amortized as that fuel is burned until an agreement is reached with the DOE for recovery of these costs.

In December 2003, APS, in conjunction with other nuclear plant operators, filed suit against the DOE on behalf of the Palo Verde Participants to recover monetary damages associated with the delay in the DOE's acceptance of spent fuel. APS pursued a damages claim for costs incurred through December 2006 in a trial that began on January 28, 2009. On June 18, 2010, the court awarded APS and the other Palo Verde Participants approximately $30 million. In October 2010, the Company received $4.8 million, representing its share of the award. The majority of the award was refunded to customers through the applicable fuel adjustment clauses. APS is continuing to pursue settlement of damage claims for costs incurred after 2006.

Disposal of Low-level Radioactive Waste. Congress has established requirements for the disposal by each state of low-level radioactive waste generated within its borders. The construction and opening of low-level radioactive waste disposal sites have been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed sites. The opposition, delays, uncertainty and costs that have been experienced demonstrate possible roadblocks that may be encountered when Arizona seeks to open its own waste repository. APS currently believes that interim low-level waste storage methods are or will be available to allow each Palo Verde unit to continue to operate and to store safely low-level waste until a permanent disposal facility is available.

Oversight of the Nuclear Energy Industry in the Wake of the Earthquake and Tsunami in Japan. On March 11, 2011, a 9.0 magnitude earthquake occurred off the northeastern coast of Japan. The earthquake produced a tsunami that caused significant damage to the Fukushima Daiichi Nuclear Power Station in Japan. Preliminary data available from the Fukushima Daiichi plant operator and Japanese government have each indicated that the earthquake and tsunami were beyond the plant's required licensing and design parameters. Validation of that data will continue as more information becomes available.

Following the March 11, 2011 earthquake and tsunami in Japan, the NRC launched a two-pronged review of U.S. nuclear power plant safety. The NRC supported the establishment of an agency task force to conduct both a near- and long-term analysis of the lessons that can be learned from the situation in Japan. The near-term task force issued a report on July 12, 2011, and on October 3, 2011, the NRC staff issued a plan for implementing the near-term task force's recommendations.

On October 18, 2011, the NRC Commissioners directed the NRC staff to implement, without delay, the near-term task force recommendations, subject to certain conditions. One such condition is that the agency should strive to complete and implement lessons learned from the earthquake and tsunami in Japan within five years. A second condition is that the staff should designate the recommendation for a rulemaking to address extended loss of offsite power to be completed within 24 to 30 months.

Until further action is taken by the NRC as a result of this event, the Company cannot predict any financial or operational impacts on Palo Verde.

Liability and Insurance Matters. The Palo Verde participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under federal law, which is currently at $12.6 billion. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $375 million, and the balance is covered by an industry-wide retrospective assessment program. If a loss at a nuclear power plant covered by the programs exceeds the accumulated funds in the primary level of protection, the Company could be assessed retrospective premium adjustments on a per incident basis. Under federal law, the maximum assessment per reactor under the program for each nuclear incident is approximately $117.5 million, subject to an annual limit of $17.5 million. Based upon the Company's 15.8% interest in the three Palo Verde units, the Company's maximum potential assessment per incident for all three units is approximately $55.7 million, with an annual payment limitation of approximately $8.3 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.75 billion, a substantial portion of which must first be applied to stabilization and decontamination. The Company has also secured insurance against portions of any increased cost of generation or purchased power and business interruption resulting from a sudden and unforeseen outage of any of the three units. The insurance coverage discussed in this and the previous paragraph is subject to certain policy conditions and exclusions. A mutual insurance company whose members are utilities with nuclear facilities issues these policies. If losses at any nuclear facility covered by this mutual insurance company were to exceed the accumulated funds for these insurance programs, the Company could be assessed retrospective premium adjustments of up to $9.57 million for the current policy period.

F. Accounting for Asset Retirement Obligations

The Company complies with FERC Order No. 631 for asset retirement obligations ("ARO"). FERC Order No. 631 affects the accounting for the decommissioning of the Company’s Palo Verde and Four Corners Stations and the method used to report the decommissioning obligation. The Company also complies with FASB guidance for conditional asset retirements which primarily affects the accounting for the disposal obligations of the Company’s fuel oil storage tanks, water wells, evaporative ponds and asbestos found at the Company’s gas-fired generating plants. The Company’s AROs are subject to various assumptions and determinations such as: (i) whether a legal obligation exists to remove assets; (ii) estimation of the fair value of the costs of removal; (iii) when final removal will occur; (iv) future changes in decommissioning cost escalation rates; and (v) the credit-adjusted interest rates to be utilized in discounting future liabilities. Changes that may arise over time with regard to these assumptions and determinations will change amounts recorded in the future as an expense for AROs. The Company records the increase in the ARO due to the passage of time as an operating expense (accretion expense). If the Company incurs or assumes any liability in retiring any asset at the end of its useful life without a legal obligation to do so, it will record such retirement costs as incurred.

The 2011 ARO liability for Palo Verde is based upon the estimated cost of decommissioning the plant from the 2010 Palo Verde decommissioning study. See Note E. The ARO liability is calculated by adjusting the estimated decommissioning costs for spent fuel storage and a profit margin and market-risk premium factor. The resulting costs are escalated over the remaining life of the plant and finally discounted using a credit-risk adjusted discount rate. As Palo Verde approaches the end of its estimated useful life, the difference between the ARO liability and future current cost estimates will narrow over time due to the accretion of the ARO liability. Because the DOE is obligated to assume responsibility for the permanent disposal of spent fuel, spent fuel costs have not been included in the ARO calculation. The Company has six external trust funds with an independent trustee that are legally restricted to settling its ARO at Palo Verde. The fair value of the funds at December 31, 2011 is $168.0 million.

FERC Order No. 631 requires the Company to revise its previously recorded ARO for any changes in estimated cash flows including changes in estimated probabilities related to timing of settlements. Any changes that result in an upward revision to estimated cash flows shall be treated as a new liability. Any downward revisions to the estimated cash flows result in a reduction to the previously recorded ARO. In April 2011, the Company implemented the 2010 Palo Verde decommissioning study, and as a result, revised its ARO related to Palo Verde to (i) increase estimated cash flows from the 2007 Study to the 2010 Study, and (ii) change estimated probabilities due to Palo Verde license extension (see Note E). The assumptions used to calculate the original ARO liability and the revised ARO liability are as follows:

	Escalation Rate	Credit-Risk Adjusted Discount Rate
Original ARO liability	3.60%	9.50%
Incremental ARO liability	3.60%	6.20%

A roll forward of the Company's ARO liability is presented below and revisions to estimates include both the increase to estimated cash flows and the change in estimated probabilities due to Palo Verde license extension.

	2011	2010
ARO liability at beginning of year	$ 92,911	$ 85,358
Liabilities incurred	—	—
Liabilities settled	(793)	(85)
Revisions to estimate	(41,670)	(377)
Accretion expense	5,692	8,015
ARO liability at end of year	$ 56,140	$ 92,911

The Company has transmission and distribution lines which are operated under various property easement agreements. If the easements were to be released, the Company may have a legal obligation to remove the lines; however, the Company has assessed the likelihood of this occurring as remote. The majority of these easements include renewal options which the Company routinely exercises.

G. Common Stock

Overview

The Company's common stock has a stated value of $1 per share, with no cumulative voting rights or preemptive rights. Holders of the common stock have the right to elect the Company's directors and to vote on other matters.

Long-Term Incentive Plan

On May 2, 2007, the Company's shareholders approved a stock-based long-term incentive plan (the "2007 LTIP") and authorized the issuance of up to one million shares of common stock for the benefit of directors and employees. Under the 2007 LTIP, common stock may be issued through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock, performance stock, cash-based awards and other stock-based awards. The Company may issue new shares, purchase shares on the open market, or issue shares from shares the Company has repurchased to meet the share requirements of the 2007 LTIP. As discussed in Note A, the Company accounts for its stock-based long-term incentive plan under FASB guidance for stock-based compensation.

Stock Options. Stock options have been granted at exercise prices equal to or greater than the market value of the underlying shares at the date of grant. The fair value for these options was estimated at the grant date using the Black-Scholes option pricing model. The options expire ten years from the date of grant unless terminated earlier by the Board of Directors (the "Board"). Stock options have not been granted since 2003.

The following table summarizes the transactions in the Company's stock options for 2011:

	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (In thousands)	Cash Received (In thousands)	Realized Current Tax Benefits (In thousands)
Options outstanding at December 31, 2010	101,246	$ 12.82				
Options exercised	53,910	12.83			$ 692	$ 327
Options outstanding at December 31, 2011	47,336	12.80	0.99	$ 1,034		
Exercisable at December 31, 2011	47,336	12.80	0.99	1,034		

The intrinsic value of stock options exercised in 2011 and 2010 were $1.0 million and $1.3 million, respectively. No options were forfeited, vested or expired during 2011 and 2010.

All stock options outstanding have vested. No compensation cost was recognized in 2010 and 2011 for stock options and there is no unrecognized compensation expense related to stock options.

Restricted Stock. The Company has awarded restricted stock under its long-term incentive plan. Restrictions from resale generally lapse and awards vest over periods of one to three years. The market value of the unvested restricted stock at the date of grant is amortized to expense over the restriction period net of anticipated forfeitures.

The expense, deferred tax benefit, and current tax expense recognized related to restricted stock awards in 2011 and 2010 is presented below (in thousands):

	2011	2010
Expense	$ 2,258	$ 1,589
Deferred tax benefit	790	556
Current tax expense (benefit) recognized (a)	(518)	(169)

(a) Any capitalized costs related to these expenses would be less than $0.1 million for all years.

The aggregate intrinsic value and fair value at grant date of restricted stock which vested in 2011 and 2010 is presented below (in thousands):

	2011	2010
Aggregated intrinsic value	$ 3,279	$ 1,749
Fair value at grant date	1,799	1,265

The unvested restricted stock transactions for 2011 are presented below:

	Total Shares		Weighted Average Grant Date Fair Value		Unrecognized Compensation Expense (a) (In thousands)		Aggregate Intrinsic Value (In thousands)
Restricted shares outstanding at December 31, 2010	143,371	$	18.30				
Restricted stock awards	118,110		28.98				
Lapsed restrictions and vesting	(103,096)		17.45				
Forfeitures	(2,200)		23.20				
Restricted shares outstanding at December 31, 2011	156,185		26.87	$	2,136	$	5,410

(a) The unrecognized compensation expense is expected to be recognized over the weighted average remaining contractual term of the outstanding restricted stock of approximately two years.

The weighted average fair values per share at grant date for restricted stock awarded during 2011 and 2010 were:

		2011		2010
Weighted average fair value per share	$	28.98	$	20.03

The holder of a restricted stock award has rights as a shareholder of the Company, including the right to vote and receive cash dividends on restricted stock.

Performance Shares. The Company has granted performance share awards to certain officers under the Company's existing long-term incentive plan, which provides for issuance of Company stock based on the achievement of certain performance criteria over a three-year period. The payout varies between 0% to 200% of performance share awards.

Detail of performance shares vested follows:

Date Vested	Payout Ratio	Performance Shares Awarded		Compensation Costs Expensed (In thousands)	Compensation Costs Expensed Period		Aggregated Intrinsic Value (In thousands)
January 1, 2012	175.0%	174,038	$	1,193	2009-2011	$	6,029
July 9, 2011	112.5%	2,250		23	2008-2011		75
September 3, 2011	112.5%	3,825		40	2008-2011		129
January 1, 2011	112.5%	34,820		565	2008-2010		959
January 1, 2010	30.0%	9,525		662	2007-2009		193

In 2012, 2013 and 2014, subject to meeting certain performance criteria, additional performance shares could be awarded. In accordance with FASB guidance related to stock-based compensation, the Company recognizes the related compensation expense by ratably amortizing the grant date fair value of awards over the requisite service period and the compensation expense is only adjusted for forfeitures. Excluding the 174,038 shares that vested on January 1, 2012, the actual number of shares to be issued can range from zero to 392,328 shares.

The fair value at the date of each separate grant of performance shares was based upon a Monte Carlo simulation. The Monte Carlo simulation reflected the structure of the performance plan which calculates the share payout on performance of the Company relative to a defined peer group over a three-year performance period based upon total return to shareholders. The fair value was determined as the average payout of one million simulation paths discounted to the grant date using a risk-free interest rate based upon the constant maturity treasury rate yield curve at the grant date. The expected volatility of total return to shareholders is calculated in accordance with the plan's term structure and includes the volatilities of all members of the defined peer group.

The outstanding performance share awards at the 100% performance level is summarized below:

	Number Outstanding	Weighted Average Grant Date Fair Value	Unrecognized Compensation Expense (a) (in thousands)	Aggregate Intrinsic Value (in thousands)
Performance shares outstanding at December 31, 2010	219,800	$ 15.86		
Performance share awards	112,164	23.45		
Performance shares vested	(36,350)	17.27		
Performance shares lapsed	—	—		
Performance shares forfeited	—	—		
Performance shares outstanding at December 31, 2011	295,614	18.57	$ 1,825	$ 10,240

(a) The unrecognized compensation expense is expected to be recognized over the weighted average remaining contractual term of the awards of approximately one year.

A summary of information related to performance shares for 2011 and 2010 is presented below:

	2011	2010
Weighted average per share grant date fair value per share of performance shares awarded	$ 23.45	$ 19.82
Fair value of performance shares vested (in thousands)	628	663
Intrinsic value of performance shares vested (in thousands)	1,032	193
Compensation expense (in thousands) (a)	1,573	988
Deferred tax expense related to compensation expense (in thousands)	551	346

(a) Includes cumulative adjustments for forfeiture of performance share awards by certain executives.

Repurchase Program

Detail regarding the Company's stock repurchase program are presented below:

	Since 1999 (a)	Twelve Months Ended December 31,	Authorized Shares
Shares repurchased	25,406,184	2,782,455	
Cost, including commission (in thousands)	$ 423,647	$ 86,508	
2010 Plan balance at December 31, 2010			676,271
2011 Plan repurchase shares authorized (b)			2,500,000
Total remaining shares available for repurchase at December 31, 2011			393,816

(a) Represents repurchased shares and cost since inception of the stock repurchase program in 1999.
(b) On March 21, 2011, the Board of Directors authorized an additional repurchase of the Company’s common stock (the "2011 Plan").

The Company may in the future make purchases of its common stock pursuant to its authorized program in open market transactions at prevailing prices and may engage in private transactions where appropriate. The repurchased shares will be available for issuance under employee benefit and stock incentive plans, or may be retired.

Dividend Policy

On December 30, 2011, the Company paid $8.8 million of quarterly dividends to shareholders. The Company paid a total of $27.2 million in cash dividends during the twelve months ended December 31, 2011. On January 26, 2012, the Board of Directors declared a quarterly cash dividend of $0.22 per share and on March 30, 2012 the Company paid $8.8 million of quarterly dividends to shareholders.

H. Accumulated Other Comprehensive Income

Accumulated other comprehensive income consists of the following components (in thousands):

	Net Unrealized Gains (Losses) on Marketable Securities	Unrecognized Pension and Postretirement Benefit Costs	Net Losses on Cash Flow Hedges	Accumulated Other Comprehensive Income
Balance at December 31, 2009	$ 5,867	$ (48,620)	$ (13,815)	$ (56,568)
Other comprehensive income	6,787	19,508	338	26,633
Income tax expense	(1,358)	(6,828)	(118)	(8,304)
Balance at December 31, 2010	11,296	(35,940)	(13,595)	(38,239)
Other comprehensive income (loss)	2,928	(74,827)	361	(71,538)
Income tax benefit (expense)	(563)	30,913	439	30,789
Balance at December 31, 2011	$ 13,661	$ (79,854)	$ (12,795)	$ (78,988)

I. Long-Term Debt, Financing Obligations and Capital Lease Obligations

Outstanding long-term debt, financing obligations and capital lease obligations are as follows:

	December 31, 2011	December 31, 2010
	(In thousands)	
Bonds (Account 221):		
Pollution Control Bonds (1):		
7.25% 2009 Series A refunding bonds, due 2040 (7.46% effective interest rate)	$ 63,500	$ 63,500
4.80% 2005 Series A refunding bonds, due 2040 (5.32% effective interest rate)	59,235	59,235
7.25% 2009 Series B refunding bonds, due 2040 (7.49% effective interest rate)	37,100	37,100
4.00% 2002 Series A refunding bonds, due 2032 (5.07% effective interest rate)	33,300	33,300
Total Account 221	193,135	193,135
Other Long-Term Debt (Accounts 224 and 226):		
Senior Notes (2):		
6.00% Senior Notes, net of discount, due 2035 (7.12% effective interest rate)	400,000	400,000
7.50% Senior Notes, net of discount, due 2038 (7.67% effective interest rate)	150,000	150,000
Total Account 224	550,000	550,000
Unamortized discount on long-term debt Account 226	(3,338)	(3,390)
Total long-term debt	$ 739,797	$ 739,745
Obligations Under Capital Lease – Noncurrent (Account 227):		
RGRT Senior Notes (3):		
3.67% Senior Notes, Series A, due 2015 (3.87% effective interest rate)	$ 15,000	$ 15,000
4.47% Senior Notes, Series B, due 2017 (4.62% effective interest rate)	50,000	50,000
5.04% Senior Notes, Series C, due 2020 (5.16% effective interest rate)	45,000	45,000
Total Capital Lease Obligations Noncurrent	$ 110,000	$ 110,000
Notes Payable – (Account 231):		
Revolving Credit Facility (4)	$ 20,000	$ —
Obligations Under Capital Lease - Current (Account 243):		
Revolving Credit Facility	$ 15,288	$ 6,585

(1) Pollution Control Bonds ("PCBs")

The Company has four series of tax exempt unsecured PCBs in aggregate principal amount of $193.1 million. The 4.00% 2002 Series A must be remarketed in August 2012.

(2) Senior Notes

The Senior Notes are unsecured obligations of the Company. They were issued pursuant to bond covenants that provide limitations on the Company's ability to enter into certain transactions. The 6.00% senior notes have an aggregate principal amount of $400.0 million and were issued in May 2005. The proceeds, net of a $2.3 million discount, were used to fund the retirement of the Company's first mortgage bonds. The Company amortizes the loss associated with a cash flow hedge recorded in accumulated other comprehensive income to earnings as interest expense over the life of the 6.00% senior notes. See Note O, "Financial Instruments and Investments - Treasury Rate Locks". This amortization is included in the effective interest rate of the 6.00% senior notes.

The 7.50% senior notes have an aggregate principal amount of $150.0 million and were issued in June 2008. The proceeds, net of a $1.3 million discount, were used to repay short-term borrowings of $44.0 million, fund capital expenditures and for other general corporate purposes.

(3) RGRT Senior Notes

On August 17, 2010, the Company and RGRT, a Texas grantor trust through which the Company finances its portion of fuel for Palo Verde, entered into a Note Purchase Agreement (the "Agreement") with various institutional purchasers. Under the terms of the Agreement, RGRT sold to the purchasers $110 million aggregate principal amount of senior notes (the "Notes"). The Company guarantees the payment of principal and interest on the Notes. In the Company's regulatory-basis financial statements, the obligations to the RGRT are reported as obligations under capital lease of nuclear fuel.

RGRT will pay interest on the Notes on February 15 and August 15 of each year until maturity. RGRT may redeem the Notes, in whole or in part, at any time at a redemption price equal to 100% of the principal amount to be redeemed together with the interest on such principal amount accrued to the date of redemption, plus a make-whole amount based on the prevailing market interest rates. The Agreement requires compliance with certain covenants, including a total debt to capitalization ratio. The Company was in compliance with these requirements throughout 2011.

The sale of the Notes was made by RGRT in reliance on a private placement exemption from registration under the Securities Act of 1933, as amended.

The proceeds of $109.4 million, net of issuance costs, from the sale of the Notes was used by RGRT to repay amounts borrowed under the revolving credit facility and will enable future nuclear fuel financing requirements of RGRT to be met with a combination of the Notes and amounts borrowed from the revolving credit facility.

(4) Revolving Credit Facility

Prior to November 15, 2011, the Company had available a $200 million credit facility with a four-year term ending September 2014. The credit facility provided for the financing of nuclear fuel, which was accomplished through the RGRT that borrowed under the facility to acquire and process nuclear fuel. The Company was obligated to repay the RGRT's borrowings with interest. Any amounts not borrowed by the RGRT could have been borrowed by the Company for working capital needs.

On November 15, 2011, the Company and RGRT entered into an amended and restated revolving credit agreement (the "RCF") with JP Morgan Chase Bank, N.A., as administrative agent and issuing bank, and Union Bank, N.A., as syndication agent, and various lending banks party thereto. Under the terms of the RCF, the Company and RGRT have available $200 million of credit for a term ending September 23, 2016.

On March 29, 2012, the Company and The Bank of New York Mellon Trust Company, N.A., as trustee of the Rio Grande Resources Trust, entered into the Incremental Facility Assumption Agreement (the "Assumption Agreement") related to the RCF discussed above with JPMorgan Chase Bank, N.A., as administrative agent and issuing bank, Union Bank, N.A., as syndication agent, and various lending banks party thereto. The Assumption Agreement provides for the Company's exercise in full of the accordion feature provided for under the RCF, increasing the aggregate unsecured borrowing available from $200 million to $300 million. In addition, the Assumption Agreement reflects the addition of a new lender under the RCF. No other material modifications have been made to the terms and conditions of the RCF.

The RCF provides that amounts borrowed by the Company may be used for, among other things, working capital and general corporate purposes and are recorded as notes payable on the regulatory-basis balance sheet. Amounts borrowed by RGRT may be used for, among other things, to finance the acquisition and processing of nuclear fuel. Amounts borrowed by RGRT are guaranteed by the Company and are recorded as a capital lease of nuclear fuel on the regulatory-basis balance sheet. Quarterly lease payments are made on units of heat production. The RCF is unsecured. The RCF requires compliance with certain covenants, including a total debt to capitalization ratio. The Company was in compliance with these requirements throughout 2011. As of December 31, 2011, the total amount borrowed by RGRT was $15.3 million for nuclear fuel under the RCF, and $20.0 million was outstanding under this facility for working capital and general corporate purposes. The weighted average interest rate on the RCF was 1.5% as of December 31, 2011.

As of December 31, 2011, the scheduled maturities for the next five years of long-term debt and obligations under capital lease noncurrent are as follows (in thousands):

2012	$ 33,300
2013	—
2014	—
2015	15,000
2016	—

The $35.3 million outstanding on the RCF for nuclear fuel, working capital and general corporate purposes is anticipated to be paid in 2012.

J. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2011 and 2010 are presented below (in thousands):

	December 31, 2011	December 31, 2010
Deferred tax assets:		
Capitalized revenues and other capitalized costs	$ 55,685	$ 86,349
Benefit of tax loss carryforwards	21,737	286
Pensions and benefits	84,742	58,026
Alternative minimum tax credit carryforward	19,863	18,370
Regulatory liabilities related to income taxes	14,762	20,433
Asset retirement obligation	21,987	33,257
Deferred fuel	—	6,584
Debt related items	7,228	7,449
Other	24,659	21,252
Total gross deferred tax assets	250,663	252,006
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(413,195)	(360,357)
Regulatory assets related to income taxes	(93,549)	(108,965)
Decommissioning	(20,019)	(34,114)
Deferred fuel	(2,279)	—
Other	(8,368)	(11,809)
Total gross deferred tax liabilities	(537,410)	(515,245)
Net accumulated deferred income taxes	$ (286,747)	$ (263,239)

Based on the average annual book income before taxes for the prior three years, excluding the effects of extraordinary and unusual or infrequent items, the Company believes that the net deferred tax assets will be fully realized at current levels of book and taxable income.

The Company recognized income tax expense for 2011 and 2010 as follows (in thousands):

	Years Ended December 31, 2011	2010
Income tax expense:		
Federal:		
Current	$ 2,706	$ 12,656
Deferred	49,813	33,383
Investment tax credit	(1,189)	(1,201)
Total federal income tax	$ 51,330	$ 44,838
State:		
Current	$ 2,938	$ 4,309
Deferred	(924)	701
Total state income tax	$ 2,014	$ 5,010

Current federal income tax expense for 2010 reflects taxes accrued under the alternative minimum tax ("AMT"). Deferred federal income tax for 2010 includes an offsetting AMT benefit of $9.9 million. There was no offsetting AMT benefit for 2011. As of December 31, 2011, the Company had $19.9 million of AMT credit carryforwards that have an unlimited life. As of December 31, 2011, the Company had tax loss carryforwards of $21.1 million and $0.6 million that have lives of 20 years and 5 years, respectively.

Federal income tax provisions differ from amounts computed by applying the statutory federal income tax rate of 35% to book income before federal income tax as follows (in thousands):

	Years Ended December 31, 2011	2010
Federal income tax expense computed on income at statutory rate	$ 55,127	$ 49,822
Difference due to:		
State income taxes (federal effect)	(705)	(1,579)
Investment Tax Credit amortization (net of deferred taxes)	(803)	(974)
Allowance for equity funds used during construction	(951)	(2,254)
Amortization of excess deferred taxes	(773)	(773)
Amortization of regulatory assets and liabilities	(433)	(510)
Patient Protection and Affordable Care Act	—	4,787
Permanent tax differences	174	(3,804)
Other	(306)	123
Total federal income tax expense	$ 51,330	$ 44,838

The Company files income tax returns in the U.S. federal jurisdiction and in the states of Texas, New Mexico and Arizona. The Company is no longer subject to tax examination by the taxing authorities in the federal jurisdiction for years prior to 2007 and in the state jurisdictions for years prior to 1998. A deficiency notice relating to the Company's 1998 through 2003 income tax returns in Arizona contests a pollution control credit, a research and development credit and the sales and property apportionment factors. The Company is contesting these adjustments.

On March 23, 2010, the Patient Protection and Affordable Care Act ("PPACA") was signed into law. A major provision of the law is that, beginning in 2013, the income tax deductions for the cost of providing certain prescription drug coverage will be reduced by the amount of the Medicare Part D subsidies received. The Company was required to recognize the impacts of the tax law change at the time of enactment and recorded a one-time non-cash charge to income tax expense of approximately $4.8 million in the first quarter of 2010.

FASB guidance prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. In January 2010, the Company filed for a change of accounting method with the IRS related to the way in which units of property are determined for purposes of determining capitalized tax assets. The change was included in the 2009 federal income tax return, with additional amounts included in the 2010 federal income tax return.

The Company recognizes in interest and penalties expense accounts interest and penalties related to tax benefits that are uncertain. During the years ended December 31, 2011 and 2010, the Company recognized expense of approximately $0.2 million and a benefit of $0.1 million, respectively in interest. The Company had approximately $0.4 million and $0.2 million for the payment of interest and penalties accrued at December 31, 2011 and December 31, 2010, respectively.

K. Commitments, Contingencies and Uncertainties

Power Purchase and Sale Contracts

To supplement its own generation and operating reserves and to meet required renewable portfolio standards, the Company engages in firm power purchase arrangements which may vary in duration and amount based on evaluation of the Company's resource needs, the economics of the transactions, and specific renewable portfolio requirements. The Company had entered into the following significant agreements with various counterparties for forward firm purchases and sales of electricity:

Type of Contract	Counterparty	Quantity			Term	Commercial Operation Date
Power Purchase and Sale Agreement	Freeport		125	MW	December 2008 through December 2013	N/A
Power Purchase and Sale Agreement	Freeport		100	MW	January 2014 through December 2021	N/A
Power Purchase Agreement	Shell	Up to	40	MW	January 2011 through September 2014	N/A
Power Purchase Agreement	NRG		20	MW	August 2011 through July 2031	August 2011
Power Purchase Agreement	Sun Edison 1		12	MW	25 years after operational start date	2012
Power Purchase Agreement	Sun Edison 2		10	MW	25 years after operational start date	2012
Power Purchase Agreement	NextEra Energy Resources		5	MW	July 2011 through June 2036	July 2011

The Company has a Power Purchase and Sale Agreement with Freeport-McMoran Copper and Gold Energy Services LLC ("Freeport") which provides for Freeport to deliver energy to the Company from its ownership interest in the Luna Energy Facility (a natural gas-fired combined cycle generation facility located in Luna County, New Mexico) and for the Company to deliver a like amount of energy at Greenlee, Arizona. The Company may purchase the quantities noted in the table above at a specified price at times when energy is not exchanged under the Power Purchase and Sale Agreement. Upon mutual agreement, the contract allows the parties to increase the amount of energy that is purchased and sold under the Power Purchase and Sale Agreement. The parties have agreed to increase the amount to 125 MW through December 2013. The contract was approved by the FERC and continues through December 31, 2021.

The Company entered into an agreement in 2009 to purchase capacity and unit contingent energy during 2010 from Shell Energy North America ("Shell"). Under the agreement, the Company provides natural gas to Pyramid Unit No. 4 where Shell has the right to convert natural gas to electric energy. The Company entered into a contract with Shell on May 17, 2010 to extend the term of the capacity and unit contingent energy purchase from January 1, 2011 through September 30, 2014.

The Company entered into a 20-year contract with NRG Solar Roadrunner LLC ("NRG") for the purchase of all of the output of a solar photovoltaic plant built in southern New Mexico which began commercial operation in August 2011. The Company has a 25-year purchase power agreement with NextEra Energy Resource for a solar photovoltaic project located in southern New Mexico which began commercial operation in July 2011. The Company has 25-year purchase power agreements for two additional solar photovoltaic projects located in southern New Mexico, SunEdison 1 and SunEdison 2 which commercial operation is estimated to begin in 2012. The Company entered into these contracts to help meet its renewable portfolio requirements.

The Company provides firm capacity and associated energy to the RGEC pursuant to an ongoing contract which requires a two-year notice to terminate. The Company also provides network integrated transmission service to RGEC pursuant to the Company's Open Access Transmission Tariff ("OATT"). The contract includes a formula-based rate that is updated annually to recover non-fuel generation costs and a fuel adjustment clause designed to recover all eligible fuel and purchased power costs allocable to RGEC.

Environmental Matters

General. The Company is subject to laws and regulations with respect to air, soil and water quality, waste disposal and other environmental matters by federal, state, regional, tribal and local authorities. Those authorities govern facility operations and have continuing jurisdiction over facility modifications. Failure to comply with these requirements can result in actions by regulatory agencies or other authorities that might seek to impose on the Company administrative, civil and/or criminal penalties or other sanctions. In addition, releases of pollutants or contaminants into the environment can result in costly cleanup liabilities. These laws and regulations are subject to change and, as a result of those changes, the Company may face additional capital and operating costs to comply. Certain key environmental issues, laws and regulations facing the Company are described further below.

Air Emissions. The U.S. Clean Air Act ("CAA") and comparable state laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide ("SO_2"), particulate matter ("PM"), nitrogen oxides ("NOx") and mercury.

Clean Air Interstate Rule. The U.S. Environmental Protection Agency's ("EPA") Clean Air Interstate Rule ("CAIR"), as applied to the Company, involves requirements to limit emissions of NOx from the Company's power plants in Texas and/or purchase allowances representing other parties' emissions reductions starting in 2009. The U.S. Court of Appeals for the District of Columbia voided CAIR in 2008; however, the Company has complied with CAIR since 2009, and such rule is binding. The annual reconciliation to comply with CAIR is due by March 31 of the following year. The Company has purchased allowances and expensed the following costs to meet its annual requirements (in thousands):

Compliance Year	**Amount**
2010	$ 370
2011	62

Cross-State Air Pollution Rule. In July 2011, the EPA finalized the Cross-State Air Pollution Rule ("CSAPR") which is intended to replace CAIR. CSAPR requires 28 states, including Texas, to further reduce power plant emissions of SO_2 and NOx. Under CSAPR, reductions in annual SO_2 and NOx emissions were required to begin January 1, 2012, with further reductions required beginning January 1, 2014. On December 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit issued its ruling to stay CSAPR, including the supplemental final rule, pending judicial review, which delays CSAPR's implementation date beyond January 1, 2012. The court is scheduled to hear the cases against the rule in April 2012. Under this timeframe, the court could issue its decision by summer or early fall 2012. As the outcome of the judicial review and any other legal or Congressional challenges are uncertain, the Company is unable to determine what impact CSAPR may ultimately have on its operations and consolidated financial results, but it could be material. Until the legal challenges to CSAPR are resolved, the Company's obligations under CAIR remains in effect.

National Ambient Air Quality Standards. Under the CAA, the EPA sets National Ambient Air Quality Standards ("NAAQS") for six criteria emissions considered harmful to public health and the environment, including PM, NOx, CO and SO_2. Areas meeting the NAAQS are designated attainment areas while those that do not meet the NAAQS are considered nonattainment areas. Each state must develop a plan to bring nonattainment areas into compliance with the NAAQS. NAAQS must be reviewed by the EPA at five-year intervals. In 2010, the EPA strengthened the NAAQS for both NOx and SO_2. The Company is currently evaluating what impact this could have on its operations. If the Company is required to install additional equipment to control emissions at its facilities, the revised NAAQS could have a material impact on its operations and consolidated financial results. In addition, the EPA is currently reviewing the PM NAAQS. The Company cannot at this time predict the impact of this review and any possible new standards on its operations or consolidated financial results, but it could be material. The EPA had been in the process of revising the NAAQS for ozone. However, in September 2011, President Obama ordered the EPA to withdraw its proposal. Work, however, is underway to support EPA's planned reconsideration of the standards in 2013.

Utility MACT. The operation of coal-fired power plants, such as the Company's Four Corners plant, results in emissions of mercury and other air toxics. In December 2011, the EPA finalized Mercury and Air Toxics Standards (known as the "Utility MACT") for power plants, which replaces the prior federal Clean Air Mercury Rule and requires significant reductions in emissions of mercury and other air toxics. Companies impacted by the new standards will have up to four (and in certain cases five) years to comply. The Company is currently evaluating the new standards and cannot at this time determine the impact they may have on its Four Corners plant, but the cost of compliance could be material.

Climate Change. A significant portion of the Company's generation assets are nuclear or gas-fired, and as a result, the Company believes that its greenhouse gas ("GHG") emissions are low relative to electric power companies who rely on more coal-fired generation. However, regulations governing the emission of GHGs, such as carbon dioxide, could impose significant costs or limitations on the Company. In recent years, the U.S. Congress has considered new legislation to restrict or regulate GHG emissions, although federal efforts directed at enacting comprehensive climate change legislation stalled in 2010 and appear unlikely to recommence in the near future. Nonetheless, it is possible that federal legislation related to GHG emissions will be considered by Congress in the future. The EPA has also proposed using the CAA to limit carbon dioxide and other GHG emissions, and other measures are being imposed or offered by individual states, municipalities and regional agreements with the goal of reducing GHG emissions.

In September 2009, the EPA adopted a rule requiring approximately 10,000 facilities comprising a substantial percentage of annual U.S. GHG emissions to inventory their emissions starting in 2010 and to report those emissions to the EPA beginning in 2011. The Company's fossil fuel-fired power generating assets are subject to this rule, and the first report containing 2010 emissions was submitted to the EPA prior to the September 30, 2011 due date. The Company also has inventoried and implemented procedures for electrical equipment containing sodium hexafluoride ("SF6"), another GHG. The Company is tracking these GHG emissions pursuant to the EPA's new SF6 reporting rule that was finalized in late 2010 and became effective January 1, 2011. The first report to EPA under this rule was originally due on March 31, 2012, but in November 2011, EPA delayed its submittal to September 26, 2012.

The EPA has also proposed and finalized other rulemakings on GHG emissions that affect electric utilities. Under EPA regulations finalized in May 2010 (referred to as the "Tailoring Rule"), the EPA began regulating GHG emissions from certain stationary sources in January 2011. The regulations are being implemented pursuant to two CAA programs: the Title V Operating Permit program and the program requiring a permit if undergoing construction or major modifications (referred to as the "PSD" program). Obligations relating to Title V permits will include recordkeeping and monitoring requirements. With respect to PSD permits, projects that cause a significant increase in GHG emissions (currently defined to be more than 75,000 tons or 100,000 tons per year, depending on various factors), will be required to implement "best available control technology," or "BACT". Pursuant to the rule, the EPA may reduce the 75,000 tons threshold referenced above in 2012 or thereafter. The EPA has issued guidance on what BACT entails for the control of GHGs, and individual states are now required to determine what controls are required for facilities within their jurisdiction on a case-by-case basis. The ultimate impact of these new regulations on the Company's operations cannot be determined at this time, but the cost of compliance with new regulations could be material. Also, on December 23, 2010, the EPA announced a settlement agreement with states and environmental groups regarding setting new source performance standards for GHG emissions from new and existing coal-, gas- and oil-based power plants. Pursuant to this agreement, and certain agreed upon extensions, the EPA intends to issue proposed rules for new and modified electric generating units ("EGUs") in 2012. It is unclear when the EPA will propose a GHG New Source Performance Standard ("NSPS") for existing EGUs and how stringent it would be, but this rule is expected. The impact of these rules on the Company is unknown at this time, but they could result in significant costs.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to consider how to address GHG emissions and are actively considering the development of emission inventories or regional GHG cap and trade programs.

It is not currently possible to predict with confidence how any pending, proposed or future GHG legislation by Congress, the states, or multi-state regions or regulations adopted by EPA or the state environmental agencies will impact the Company's business. However, any such legislation or regulation of GHG emissions or any future related litigation could result in increased compliance costs or additional operating restrictions or reduced demand for the power the Company generates, could require the Company to purchase rights to emit GHG, and could have a material adverse effect on the Company's business, financial condition, reputation or results of operations.

Climate change also has potential physical effects that could be relevant to the Company's business. In particular, some studies suggest that climate change could affect the Company's service area by causing higher temperatures, less winter precipitation and less spring runoff, as well as by causing more extreme weather events. Such developments could change the demand for power in the region and could also impact the price or ready availability of water supplies or affect maintenance needs and the reliability of Company equipment.

The Company believes that material effects on the Company's business or operations may result from the physical consequences of climate change, the regulatory approach to climate change ultimately selected and implemented by governmental authorities, or both. Substantial expenditures may be required for the Company to comply with such regulations in the future and, in some instances, those expenditures may be material. Given the very significant remaining uncertainties regarding whether and how these issues will be regulated, as well as the timing and severity of any physical effects of climate change, the Company believes it is impossible at present to meaningfully quantify the costs of these potential impacts.

Contamination Matters. The Company has a provision for environmental remediation obligations of approximately $0.3 million at December 31, 2011, related to compliance with federal and state environmental standards. However, unforeseen expenses associated with environmental compliance or remediation may occur and could have a material adverse effect on the future operations and financial condition of the Company.

The Company incurred the following expenditures to comply with federal environmental statutes (in thousands):

	Years Ended December 31,	
	2011	**2010**
Clean Air Act	$ 716	$ 615
Clean Water Act (1)	264	178

(1) 2011 excludes a reduction of approximately $0.1 million related to an adjustment for estimated remediation costs for Copper generating station.

The EPA has investigated releases or potential releases of hazardous substances, pollutants or contaminants at the Gila River Boundary Site, on the Gila River Indian Community reservation in Arizona and designated it as a Superfund site. The Company currently owns 16.29% of the site and will share in the cost of cleanup of this site. The Company has an agreement with the EPA and a former property owner to resolve this matter and on June 30, 2011, the Company entered into a consent decree with the EPA at a cost to the Company of less than $0.1 million.

Environmental Litigation and Investigations. On April 6, 2009, APS received a request from the EPA under Section 114 of the CAA seeking detailed information regarding projects and operations at Four Corners. The EPA has taken the position that many utilities have made certain physical or operational changes at their plants that should have triggered additional regulatory requirements under the New Source Review provisions of the CAA. APS responded to this request in 2009. The Company is unable to predict the timing or content of the EPA's response, if any, or any resulting actions.

The Company received word that Earthjustice filed a lawsuit in the United States District Court for New Mexico on October 4, 2011 for alleged violations of the Prevention of Significant Deterioration provisions of the CAA. Subsequent to filing its original Complaint, on January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the CAA's NSPS program. Among other things, the plaintiffs seek to have the court enjoin operations at Four Corners until APS applies for and obtains any required PSD permits and complies with the NSPS. The plaintiffs further request the court to order the payment of civil penalties, including a beneficial mitigation project. APS advised that it believes the claims in this matter are without merit and will vigorously defend against them. The Company is unable to predict the outcome of these alleged violations.

Lease Agreements

The Company leases land in El Paso adjacent to the Newman Power Station under a lease which expires in June 2033 with a renewal option of 25 years. In addition, the Company leases certain warehouse facilities in El Paso under a lease which expires in December 2014. The Company also has several other leases for office and parking facilities which expire within the next five years. These lease agreements do not impose any restrictions relating to issuance of additional debt, payment of dividends or entering into other lease arrangements. The Company has no significant capital lease agreements.

The Company's total annual rental expense related to operating leases was $1.1 million for 2011 and 2010. As of December 31, 2011, the Company's minimum future rental payments for the next five years are as follows (in thousands):

2012	$	1,030
2013		951
2014		919
2015		477
2016		438

L. Litigation

The Company is a party to various legal actions. In many of these matters, the Company has excess casualty liability insurance that covers the various claims, actions and complaints. Based upon a review of these claims and applicable insurance coverage, to the extent that the Company has been able to reach a conclusion as to its ultimate liability, it believes that none of these claims will have a material adverse effect on the financial position, results of operations or cash flows of the Company.

See Note C and Note K for discussion of the effects of government legislation and regulation on the Company.

M. Employee Benefits

Retirement Plans

The Company's Retirement Income Plan (the "Retirement Plan") covers employees who have completed one year of service with the Company and work at least a minimum number of hours each year. The Retirement Plan is a qualified noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the Retirement Plan are used to pay benefit obligations under the Retirement Plan. Contributions from the Company are at least the minimum funding amounts required by the IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, debt securities and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company has two non-qualified retirement plans that are non-funded defined benefit plans. The Company's Supplemental Retirement Plan covers certain former employees and directors of the Company. The other plan, the Excess Benefit Plan was adopted in 2004 and covers certain active and former employees of the Company. The benefit cost for the non-qualified retirement plans are based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan. The Company complies with FASB guidance on disclosure for pension and other post-retirement plans that requires disclosure of investment policies and strategies, categories of investment and fair value measurements of plan assets, and significant concentrations of risk.

The obligations and funded status of the plans are presented below (in thousands):

	December 31,			
	2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Change in projected benefit obligation:				
Benefit obligation at end of prior year	$ 242,718	$ 24,008	$ 215,944	$ 21,767
Service cost	6,590	260	5,888	176
Interest cost	12,871	1,116	12,507	1,122
Amendments	—	—	—	838
Actuarial loss	42,508	2,980	16,008	1,822
Benefits paid	(8,394)	(1,817)	(7,629)	(1,717)
Benefit obligation at end of year	296,293	26,547	242,718	24,008
Change in plan assets:				
Fair value of plan assets at end of prior year	171,341	—	155,140	—
Actual return on plan assets	16,422	—	17,030	—
Employer contribution	12,000	1,817	6,800	1,717
Benefits paid	(8,394)	(1,817)	(7,629)	(1,717)
Fair value of plan assets at end of year	191,369	—	171,341	—
Funded status at end of year	$ (104,924)	$ (26,547)	$ (71,377)	$ (24,008)

Amounts recognized in the Company's regulatory-basis balance sheets consist of the following (in thousands):

	December 31,			
	2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Current liabilities	$ —	$ (1,844)	$ —	$ (1,914)
Noncurrent liabilities	(104,924)	(24,703)	(71,377)	(22,094)
Total	$ (104,924)	$ (26,547)	$ (71,377)	$ (24,008)

The accumulated benefit obligation in excess of plan assets is as follows (in thousands):

	December 31,			
	2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Projected benefit obligation	$ (296,293)	$ (26,547)	$ (242,718)	$ (24,008)
Accumulated benefit obligation	(250,753)	(26,547)	(205,167)	(23,538)
Fair value of plan assets	191,369	—	171,341	—

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands):

	Years Ended December 31, 2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 129,820	$ 8,990	$ 95,828	$ 6,364
Prior service cost	24	408	46	502
Total	$ 129,844	$ 9,398	$ 95,874	$ 6,866

The following are the weighted-average actuarial assumptions used to determine the benefit obligations:

	December 31, 2011			2010		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan
Discount rate	4.3%	3.6%	4.1%	5.4%	4.6%	5.3%
Rate of compensation increase	5.0%	N/A	5.0%	5.0%	N/A	5.0%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan. A 1% increase in the discount rate would decrease the December 31, 2011 retirement plans' projected benefit obligation by 12.7%. A 1% decrease in the discount rate would increase the December 31, 2011 retirement plans' projected benefit obligation by 15.8%.

The components of net periodic benefit cost are presented below (in thousands):

	Years Ended December 31, 2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Service cost	$ 6,590	$ 260	$ 5,888	$ 176
Interest cost	12,871	1,116	12,507	1,122
Amendments	—	—	—	838
Expected return on plan assets	(14,095)	—	(13,867)	—
Amortization of:				
Net loss	6,190	354	3,331	218
Prior service cost	21	94	21	94
Net periodic benefit cost	$ 11,577	$ 1,824	$ 7,880	$ 2,448

The changes in benefit obligations recognized in other comprehensive income are presented below (in thousands):

	Years Ended December 31,			
	2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 40,181	$ 2,980	$ 12,844	$ 1,822
Amortization of:				
Net loss	(6,190)	(354)	(3,331)	(218)
Prior service cost	(21)	(94)	(21)	(94)
Total expense recognized in other comprehensive income	$ 33,970	$ 2,532	$ 9,492	$ 1,510

The total amount recognized in net periodic benefit costs and other comprehensive income are presented below (in thousands):

	Years Ended December 31,			
	2011		2010	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Total recognized in net periodic benefit cost and other comprehensive income	$ 45,547	$ 4,356	$ 17,372	$ 3,958

The following are amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2012 (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 11,300	$ 560
Prior service cost	20	90

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost for the twelve months ended December 31:

	2011			2010		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan
Discount rate	5.4%	4.6%	5.3%	5.9%	5.2%	6.0%
Expected long-term return on plan assets	7.5%	N/A	N/A	7.5%	N/A	N/A
Rate of compensation increase	5.0%	N/A	5.0%	5.0%	N/A	5.0%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan.

The Company's overall expected long-term rate of return on assets is 7.5% effective January 1, 2011, which is both a pre-tax and after-tax rate as pension funds are generally not subject to income tax. The expected long-term rate of return is based on the weighted average of the expected returns on investments based upon the target asset allocation of the pension fund. The Company's target allocations for the plan's assets are presented below:

	December 31, 2011
Equity securities	50%
Fixed income	45%
Alternative investments	5%
Total	100%

The Retirement Plan fund includes a diversified portfolio of funds investing in equity securities including large and small capital funds and international funds. The Retirement Plan fund also invests in fixed income securities and a real estate limited partnership. The expected returns for fund investments are based on historical risk premiums above the current fixed income rate, while the expected returns for the fixed income securities are based on the portfolio's yield to maturity.

FASB guidance on disclosure for pension plans requires disclosure of fair value measurements of plan assets. To increase consistency and comparability in fair value measurements FASB guidance on fair value measurements established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Prices for securities held in the underlying portfolios of the Retirement Plan are primarily obtained from independent pricing services. These prices are based on observable market data for the same or similar securities.

- Level 2 – Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. The fair value of the Guaranteed Investment Contract is based on market interest rates of investments with similar terms and risk characteristics.

- Level 3 – Unobservable inputs using data that is not corroborated by market data. The fair value of the real estate limited partnership is reported at the net asset value of the investment.

The fair value of the Company's Retirement Plan assets at December 31, 2011 and 2010, and the level within the three levels of the fair value hierarchy defined by FASB guidance on fair value measurements are presented in the table below (in thousands):

Description of Securities	Fair Value as of December 31, 2011	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 6,708	$ 6,708	$ —	$ —
U.S. Treasury Securities	24,178	24,178	—	—
Guaranteed Investment Contract	608	—	608	—
Common Stock	70,893	70,893	—	—
Mutual Funds - Fixed Income	53,598	53,598	—	—
Mutual Funds - Equity	26,873	26,873	—	—
Limited Partnership Interest in Real Estate (a)	8,511	—	—	8,511
Total Plan Investments	$ 191,369	$ 182,250	$ 608	$ 8,511

Description of Securities	Fair Value as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Cash and Cash Equivalents	$ 4,975	$ 4,975	$ —	$ —
U.S. Treasury Securities	83,601	83,601	—	—
Guaranteed Investment Contract	550	—	550	—
Common Stock	54,957	54,957	—	—
Mutual Funds	19,501	19,501	—	—
Limited Partnership Interest in Real Estate (a)	7,757	—	—	7,757
Total Plan Investments	$ 171,341	$ 163,034	$ 550	$ 7,757

(a) This investment is a commercial real estate partnership that purchases land, develops limited infrastructure, and sells it for commercial development. The Company is restricted from selling its partnership interest during the life of the partnership which is generally 5-7 years. Return of investment is realized as land is sold. The fair value of the limited partnership interest in real estate is based on the net asset value of the partnership which reflects the appraised value of the land.

The table below reflects the changes in the fair value of investments in real estate during the period (in thousands):

	Fair Value of Investments in Real Estate
Balance at December 31, 2009	$ 8,288
Unrealized loss in fair value	(531)
Balance at December 31, 2010	7,757
Sale of land	(102)
Unrealized gain in fair value	856
Balance at December 31, 2011	$ 8,511

There were no purchases, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2011 and 2010.

The Company adheres to the traditional capital market pricing theory which maintains that over the long term, the risk of owning equities should be rewarded with a greater return than available from fixed income investments. The Company seeks to minimize the risk of owning equity securities by investing in funds that pursue risk minimization strategies and by diversifying its investments to limit its risks during falling markets. The investment managers have full discretionary authority to direct the investment of plan assets held in trust within the guidelines prescribed by the Company through the plan's investment policy statement including the ability to hold cash equivalents. The investment guidelines of the investment policy statement are in accordance with the Employee Retirement Income Security Act of 1974 ("ERISA") and Department of Labor ("DOL") regulations.

The Company contributes at least the minimum funding amounts required by the IRS for the Retirement Plan, as actuarially calculated. The Company expects to contribute $19.8 million to its retirement plans in 2012.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Plans
2012	$ 9,132	$ 1,844
2013	9,967	1,813
2014	10,932	1,777
2015	11,924	1,758
2016	13,021	1,801
2017-2021	83,027	9,430

Other Postretirement Benefits

The Company provides certain health care benefits for retired employees and their eligible dependents and life insurance benefits for retired employees only. Substantially all of the Company's employees may become eligible for those benefits if they retire while working for the Company. Contributions from the Company are currently based on the funding amounts established in PUCT Docket No. 37690. The assets of the plan are invested in equity securities, debt securities, and cash equivalents and are managed by professional investment managers appointed by the Company.

The Company determined that the prescription drug benefits of its plan were actuarially equivalent to the Medicare Part D benefit provided for in the Medicare Prescription Drug, Improvement, and Modernization Act of 2003. FASB guidance on accounting and disclosure requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 requires measurement of the postretirement benefit obligation, the plan assets, and the net periodic postretirement benefit cost to reflect the effects of the subsidy. In March 2010, the President signed into law comprehensive health care reform legislation under the Patient Protection and Affordable Care Act and the Health Care Education and Affordability Reconciliation Act (the "Acts"). The Company modified the operations of the plan to conform to the effective provisions of the Acts.

The following table contains a reconciliation of the change in the benefit obligation, the fair value of plan assets, and the funded status of the plans (in thousands):

	December 31, 2011	December 31, 2010
Change in benefit obligation:		
Benefit obligation at end of prior year	$ 95,254	$ 118,267
Service cost	2,988	3,558
Interest cost	5,379	6,664
Actuarial loss	32,694	(3,807)
Amendments (a)	—	(26,605)
Benefits paid	(4,180)	(3,598)
Retiree contributions	941	584
Medicare Part D subsidy	196	191
Benefit obligation at end of year	133,272	95,254
Change in plan assets:		
Fair value of plan assets at end of prior year	33,660	29,348
Actual return on plan assets	—	2,514
Employer contribution	2,200	4,621
Benefits paid	(4,180)	(3,598)
Retiree contributions	941	584
Medicare Part D subsidy	196	191
Fair value of plan assets at end of year	32,817	33,660
Funded status (b)	$ (100,455)	$ (61,594)

(a) The amendments that occurred during the twelve months ended December 31, 2010 primarily related to modifications to the required copayment levels, deductibles and out-of-pocket maximum responsibilities retained by the retired employees.

(b) These amounts are recognized in the Company's regulatory-basis balance sheets as a non-current liability.

Amounts recognized in accumulated other comprehensive income that have not been recognized as a component of net periodic cost consist of the following (in thousands):

	December 31, 2011	December 31, 2010
Net loss (gain)	$ 20,144	$ (14,411)
Prior service credit	(30,647)	(36,574)
Transition obligation	2,426	4,583
	$ (8,077)	$ (46,402)

The following are the weighted-average actuarial assumptions used to determine the accrued postretirement benefit obligations:

	December 31, 2011	December 31, 2010
Discount rate at end of year	4.3%	5.5%
Health care cost trend rates:		
Initial	8.0%	8.5%
Ultimate	5.0%	5.0%
Year ultimate reached	2026	2018

The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan. A 1% increase in the discount rate would decrease the December 31, 2011 accumulated postretirement benefit obligation by 14.1%. A 1% decrease in the discount rate would increase the December 31, 2011 accumulated postretirement benefit obligation by 17.9%.

Net periodic benefit cost is made up of the components listed below (in thousands):

	Years Ended December 31, 2011	2010
Service cost	$ 2,988	$ 3,558
Interest cost	5,379	6,664
Expected return on plan assets	(1,823)	(1,529)
Amortization of:		
Unrecognized transition obligation	2,157	2,157
Prior service benefit	(5,927)	(2,869)
Net gain	(39)	(175)
Net periodic benefit cost	$ 2,735	$ 7,806

The net periodic benefit cost includes amortization of unrecognized transition obligation over a twenty-year period beginning in 1993. The changes in benefit obligations recognized in other comprehensive income are presented below (in thousands):

	Years Ended December 31, 2011	2010
Net loss (gain)	$ 34,517	$ (4,792)
Prior service benefit	—	(26,605)
Amortization of:		
Unrecognized transition obligation	(2,157)	(2,157)
Prior service benefit	5,927	2,869
Net gain	39	175
Total recognized in other comprehensive income	$ 38,326	$ (30,510)

The total recognized in net periodic benefit cost and other comprehensive income are presented below (in thousands):

	Years Ended December 31, 2011	2010
Total recognized in net periodic benefit cost and other comprehensive income	$ 41,061	$ (22,704)

The following are amounts in accumulated other comprehensive income that are expected to be recognized as a component of net periodic benefit cost during 2012.

Unrecognized transition obligation	$ 2,157
Prior service credit	(5,880)
Net loss	640

The following are the weighted-average actuarial assumptions used to determine the net periodic benefit cost for the twelve months ended December 31:

	2011	2010
Discount rate at beginning of year	5.5%	5.9%
Expected long-term return on plan assets	5.2%	5.2%
Health care cost trend rates:		
Initial	8.5%	8.5%
Ultimate	5.0%	5.0%
Year ultimate reached	2018	2017

The discount rate is changed at each measurement date based on projected cash flows of the benefit plans using the spot rates in the Citigroup Pension Discount Curve and then solving for a single discount rate that produces the same present value of cash flows for each plan.

For measurement purposes, an 8.5% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2011. The rate was assumed to decrease gradually to 5% for 2018 and remain at that level thereafter. Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plan. The effect of a 1% change in these assumed health care cost trend rates would increase or decrease the December 31, 2011 benefit obligation by $22.8 million or $18.3 million, respectively. In addition, such a 1% change would increase or decrease the aggregate 2011 service and interest cost components of the net periodic benefit cost by $1.6 million or $1.2 million, respectively.

The Company's overall expected long-term rate of return on assets, on an after-tax basis, is 5.2% effective January 1, 2011. The expected long-term rate of return is based on the after-tax weighted average of the expected returns on investments based upon the target asset allocation. The Company's target allocations for the plan's assets are presented below:

	December 31, 2011
Equity securities	65%
Fixed income	30%
Alternative investments	5%
Total	100%

The asset portfolio includes a diversified mix of funds investing in equity securities including large and small capital funds and international funds. The asset portfolio also includes fixed income securities, cash equivalents, and a real estate limited partnership. The expected returns for fund investments are based on historical risk premiums above the current fixed income rate, while the expected returns for the fixed income securities are based on the portfolio's yield to maturity.

FASB guidance on disclosure for other postretirement plans requires disclosure of fair value measurements of plan assets. To increase consistency and comparability in fair value measurements, FASB guidance on fair value measurements established a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 – Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Prices for securities held in the underlying portfolios of the Other Postretirement Benefits Plan are primarily obtained from independent pricing services. These prices are based on observable market data for the same or similar securities.

- Level 2 – Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. The fair value of municipal securities – tax-exempt are reported at fair value based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences.

- Level 3 – Unobservable inputs using data that is not corroborated by market data. The fair value of the real estate limited partnership is reported at the net asset value of the investment.

The fair value of the Company's Other Postretirement Benefits Plan assets at December 31, 2011 and 2010, and the level within the three levels of the fair value hierarchy defined by FASB guidance on fair value measurements are presented in the table below (in thousands):

Description of Securities	**Fair Value as of December 31, 2011**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Cash and Cash Equivalents	$ 3,000	$ 3,000	$ —	$ —
Municipal Securities – Tax Exempt	12,062	—	12,062	—
Common Stock	16,159	16,159	—	—
Limited Partnership Interest in Real Estate (a)	1,596	—	—	1,596
Total Plan Investments	$ 32,817	$ 19,159	$ 12,062	$ 1,596

Description of Securities	**Fair Value as of December 31, 2010**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Cash and Cash Equivalents	$ 4,122	$ 4,122	$ —	$ —
Municipal Securities – Tax Exempt	11,348	—	11,348	—
Common Stock	16,735	16,735	—	—
Limited Partnership Interest in Real Estate (a)	1,455	—	—	1,455
Total Plan Investments	$ 33,660	$ 20,857	$ 11,348	$ 1,455

(a) This investment is a commercial real estate partnership that purchases land, develops limited infrastructure, and sells it for commercial development. The Company is restricted from selling its partnership interest during the life of the partnership which is generally 5-7 years. Return of investment is realized as land is sold. The fair value of the limited partnership interest in real estate is based on the net asset value of the partnership which reflects the appraised value of the land.

The table below reflects the changes in the fair value of the investments in real estate during the period (in thousands):

	Fair Value of Investments in Real Estate
Balance at December 31, 2009	$ 1,554
Unrealized loss in fair value	(99)
Balance at December 31, 2010	1,455
Sale of land	(19)
Unrealized gain in fair value	160
Balance at December 31, 2011	$ 1,596

There were no purchases, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2011 and 2010.

The Company adheres to the traditional capital market pricing theory which maintains that over the long term, the risk of owning equities should be rewarded with a greater return than available from fixed income investments. The Company seeks to minimize the risk of owning equity securities by investing in mutual funds that pursue risk minimization strategies and by diversifying its investments to limit its risks during falling markets. The investment managers have full discretionary authority to direct the investment of plan assets held in trust within the guidelines prescribed by the Company through the plan's investment policy statement including the ability to hold cash equivalents. The investment guidelines of the investment policy statement are in accordance with the ERISA and DOL regulations.

The Company expects to contribute $2.5 million to its other postretirement benefits plan in 2012. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

2012	$	3,519
2013		4,006
2014		4,507
2015		5,058
2016		5,614
2017-2021		35,367

401(k) Defined Contribution Plans

The Company sponsors 401(k) defined contribution plans covering substantially all employees. Historically, the Company has provided a 50 percent matching contribution up to 6 percent of the employee's compensation subject to certain other limits and exclusions. Annual matching contributions made to the savings plans for the years 2011 and 2010 were $1.7 million and $1.7 million, respectively.

Annual Short-Term Incentive Plan

The Annual Short-Term Incentive Plan (the "Incentive Plan") provides for the payment of cash awards to eligible Company employees, including each of its executive officers. Payment of awards is based on the achievement of performance measures reviewed and approved by the Company's Board of Directors' Compensation Committee. Generally, these performance measures are based on meeting certain financial, operational and individual performance criteria. The financial performance goals are based on earnings per share and the operational performance goals are based on safety, regulatory compliance, and customer satisfaction. If a specified level of earnings per share is not attained, no amounts will be paid under the Incentive Plan. The Company reached the required levels of earnings per share, safety, and regulatory compliance goals for an incentive payment of $7.3 million and $7.4 million in 2011 and 2010, respectively. The Company has renewed the Incentive Plan in 2012 with similar goals.

N. Franchises and Significant Customers

El Paso and Las Cruces Franchises

The Company has a franchise agreement with El Paso, the largest city it serves. The franchise agreement allows the Company to utilize public rights-of-way necessary to serve its retail customers within El Paso. The Company is also providing electric distribution service to Las Cruces under an implied franchise by satisfying all obligations under the franchise agreement that expired April 30, 2009.

The franchise agreements held between the Company and the cities of El Paso and Las Cruces are detailed below:

City	Period	Franchise Fee (a)
El Paso	July 1, 2005 - August 1, 2010	3.25%
El Paso	August 1, 2010 - Present	4.00% (b)
Las Cruces	February 1, 2000 - Present	2.00%

(a) Based on a percentage of revenue.
(b) The additional fee of 0.75% is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The Company's sales to the military bases represent approximately 5% of annual retail revenues. The Company signed a contract with Fort Bliss in October 2008 under which Fort Bliss takes retail electric service from the Company. The contract with Fort Bliss expired in 2010 and the Company is serving Fort Bliss under the applicable Texas tariffs. In April 1999, the Army and the Company entered into a ten-year contract to provide retail electric service to White Sands. The contract with White Sands expired in 2009 and the Company is serving White Sands under the applicable New Mexico tariffs. In March 2006, the Company signed a contract with Holloman that provides for the Company to provide retail electric service and limited wheeling services to Holloman for a ten-year term which expires in January 2016.

O. Financial Instruments and Investments

FASB guidance requires the Company to disclose estimated fair values for its financial instruments. The Company has determined that cash and temporary investments, investment in debt securities, accounts receivable, decommissioning trust funds, long-term debt and financing and capital lease obligations, accounts payable and customer deposits meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable and customer deposits approximate fair value because of the short maturity of these items. Investments in debt securities and decommissioning trust funds are carried at fair value.

Long-Term Debt, Financing Obligations and Capital Lease Obligations. The fair values of the Company's long-term debt, financing obligations, and capital lease obligations including current portion thereof, are based on estimated market prices for similar issues and are presented below (in thousands):

	December 31,			
	2011		2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Pollution Control Bonds	$ 193,135	$ 206,756	$ 193,135	$ 192,924
Senior Notes	546,662	700,371	546,610	574,700
RGRT Senior Notes (1)	110,000	116,985	110,000	110,371
RCF (1)	35,288	35,288	6,585	6,585
Total	$ 885,085	$ 1,059,400	$ 856,330	$ 884,580

(1) Nuclear fuel capital leases obligations as of December 31, 2011 is funded through the $110.0 million RGRT Senior Notes and $15.3 million under the RCF. Financing obligations consist of $20.0 million outstanding under the RCF for working capital and general corporate purposes. The interest rate on the Company's borrowings under the RCF is reset throughout the quarter reflecting current market rates. Consequently, the carrying value approximates fair value.

Treasury Rate Locks. The Company entered into treasury rate lock agreements in 2005 to hedge against potential movements in the treasury reference interest rate pending the issuance of the 6% Senior Notes. The treasury rate lock agreements met the criteria for hedge accounting and were designated as a cash flow hedge. In accordance with cash flow hedge accounting, the Company recorded the loss associated with the fair value of the cash flow hedge, net of tax, as a component of accumulated other comprehensive loss and amortizes the accumulated comprehensive loss to earnings as interest expense over the life of the 6% Senior Notes. In 2012, approximately $0.4 million of this accumulated other comprehensive loss item will be reclassified to interest expense.

Contracts and Derivative Accounting. The Company uses commodity contracts to manage its exposure to price and availability risks for fuel purchases and power sales and purchases and these contracts generally have the characteristics of derivatives. The Company does not trade or use these instruments with the objective of earning financial gains on the commodity price fluctuations. The Company has determined that all such contracts outstanding at December 31, 2011, except for certain natural gas commodity contracts with optionality features, that had the characteristics of derivatives met the "normal purchases and normal sales" exception provided in FASB guidance for accounting for derivative instruments and hedging activities, and, as such, were not required to be accounted for as derivatives.

The Company determined that certain of its natural gas commodity contracts with optionality features are not eligible for the normal purchases exception and, therefore, are required to be accounted for as derivative instruments pursuant to FASB guidance for accounting for derivative instruments and hedging activities. However, as of December 31, 2011, the variable, market-based pricing provisions of existing gas contracts are such that these derivative instruments have no significant fair value.

Marketable Securities. The Company's marketable securities, included in decommissioning trust funds in the regulatory-basis balance sheets, are reported at fair value which was $168.0 million and $153.9 million at December 31, 2011 and 2010, respectively. These securities are classified as available for sale under FASB guidance for certain investments in debt and equity securities and are valued using prices and other relevant information generated by market transactions involving identical or comparable securities. The reported fair values include gross unrealized losses on marketable securities whose impairment the Company has deemed to be temporary. The tables below present the gross unrealized losses and the fair value of these securities, aggregated by investment category and length of time that individual securities have been in a continuous unrealized loss position (in thousands):

	December 31, 2011					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities (1)**:**						
Federal Agency Mortgage Backed Securities	$ 515	$ (8)	$ 1,233	$ (23)	$ 1,748	$ (31)
U.S. Government Bonds	100	(1)	2,413	(38)	2,513	(39)
Municipal Obligations	2,275	(31)	4,731	(144)	7,006	(175)
Corporate Obligations	3,525	(118)	1,234	(43)	4,759	(161)
Total Debt Securities	6,415	(158)	9,611	(248)	16,026	(406)
Common Stock	10,688	(2,065)	1,740	(489)	12,428	(2,554)
Total Temporarily Impaired Securities	$ 17,103	$ (2,223)	$ 11,351	$ (737)	$ 28,454	$ (2,960)

(1) Includes approximately 96 securities.

	December 31, 2010					
	Less than 12 Months		12 Months or Longer		Total	
	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses	Fair Value	Unrealized Losses
Description of Securities (2)**:**						
Federal Agency Mortgage Backed Securities	$ 2,290	$ (51)	$ 441	$ (27)	$ 2,731	$ (78)
U.S. Government Bonds	9,583	(124)	—	—	9,583	(124)
Municipal Obligations	13,145	(278)	3,763	(145)	16,908	(423)
Corporate Obligations	1,855	(18)	—	—	1,855	(18)
Total Debt Securities	26,873	(471)	4,204	(172)	31,077	(643)
Common stock	6,943	(774)	4,303	(420)	11,246	(1,194)
Total Temporarily Impaired Securities	$ 33,816	$ (1,245)	$ 8,507	$ (592)	$ 42,323	$ (1,837)

(2) Includes approximately 96 securities.

The Company monitors the length of time the security trades below its cost basis along with the amount and percentage of the unrealized loss in determining if a decline in fair value of marketable securities below recorded cost is considered to be other than temporary. In addition, the Company will research the future prospects of individual securities as necessary. As a result of these factors, as well as the Company's intent and ability to hold these securities until their market price recovers, these securities are considered temporarily impaired. The Company will not have a requirement to expend monies held in trust before 2044 or a later period when the Company begins to decommission Palo Verde.

The reported fair values also include gross unrealized gains on marketable securities which have not been recognized in the Company's net income. The table below presents the unrecognized gross unrealized gains and the fair value of these securities, aggregated by investment category (in thousands):

	December 31, 2011		December 31, 2010	
	Fair Value	Unrealized Gains	Fair Value	Unrealized Gains
Description of Securities:				
Federal Agency Mortgage Backed Securities	$ 25,077	$ 1,220	$ 18,472	$ 793
U.S. Government Bonds	10,263	972	10,450	183
Municipal Obligations	30,310	1,792	15,633	592
Corporate Obligations	7,641	459	7,223	362
Total Debt Securities	73,291	4,443	51,778	1,930
Common Stock	62,479	15,681	56,770	14,142
Cash and Cash Equivalents	3,739	—	3,007	—
Total	$ 139,509	$ 20,124	$ 111,555	$ 16,072

The Company's marketable securities include investments in municipal, corporate and federal debt obligations. Substantially all of the Company's mortgage backed securities, based on contractual maturity, are due in 10 years or more. The mortgage backed securities have an estimated weighted average maturity which generally range from 3 to 7 years and reflects anticipated future prepayments. The contractual year for maturity for these available-for-sale securities as of December 31, 2011 is as follows (in thousands):

	Total	2012	2013 through 2016	2017 through 2021	2022 and Beyond
Municipal Debt Obligations	$ 37,316	$ 1,009	$ 12,892	$ 14,252	$ 9,163
Corporate Debt Obligations	12,400	1,368	3,630	4,338	3,064
U.S. Government Bonds	12,776	1,316	1,685	6,844	2,931

The Company recognizes impairment losses on certain of its securities deemed to be other than temporary. In accordance with FASB guidance, these impairment losses are recognized in net income, and a lower cost basis is established for these securities. For the twelve months ended December 31, 2011 and 2010, the Company recognized other than temporary impairment losses on its available-for-sale securities as follows (in thousands):

	2011	2010
Gross unrealized holding losses included in pre-tax income	$ (2,116)	$ (263)

The Company's marketable securities in its decommissioning trust funds are sold from time to time, and the Company uses the specific identification basis on which to determine the amount to reclassify out of accumulated other comprehensive income and into net income. The proceeds from the sale of these securities during the twelve months ended December 31, 2011 and 2010 and the related effects on pre-tax income are as follows (in thousands):

	2011	2010
Proceeds from sales of available-for-sale securities	$ 82,926	$ 61,656
Gross realized gains included in pre-tax income	$ 1,479	$ 1,030
Gross realized losses included in pre-tax income	(721)	(889)
Gross unrealized losses included in pre-tax income	(2,116)	(263)
Net losses in pre-tax income	$ (1,358)	$ (122)
Net unrealized holding gains included in accumulated other comprehensive income	$ 1,570	$ 6,665
Net losses reclassified out of accumulated other comprehensive income	1,358	122
Net gains in other comprehensive income	$ 2,928	$ 6,787

Investment in Debt Securities. As of December 31, 2011, the Company had a $2.0 million investment in an auction rate security maturing in 2044. The Company classifies this debt security as a trading security which is included in other investments on the Company's regulatory-basis balance sheets.

Fair Value Measurements. FASB guidance requires the Company to provide expanded quantitative disclosures for financial assets and liabilities recorded on the balance sheet at fair value. Financial assets carried at fair value include the Company's decommissioning trust investments and investments in debt securities which are included in deferred charges and other assets on the consolidated balance sheets. The Company has no liabilities that are measured at fair value on a recurring basis. The FASB guidance establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three levels as follows:

- Level 1 - Observable inputs that reflect quoted market prices for identical assets and liabilities in active markets. Financial assets utilizing Level 1 inputs include the nuclear decommissioning trust investments in active exchange-traded equity securities and U.S. Treasury securities that are in a highly liquid and active market.
- Level 2 - Inputs other than quoted market prices included in Level 1 that are observable for the asset or liability either directly or indirectly. Financial assets utilizing Level 2 inputs include the nuclear decommissioning trust investments in fixed income securities. The fair value of these financial instruments is based on evaluated prices that reflect observable market information, such as actual trade information of similar securities, adjusted for observable differences.
- Level 3 - Unobservable inputs using data that is not corroborated by market data and primarily based on internal Company analysis using models and various other analyses. Financial assets utilizing Level 3 inputs include the Company's investments in debt securities.

The securities in the Company’s decommissioning trust funds are valued using prices and other relevant information generated by market transactions involving identical or comparable securities. FASB guidance identifies this valuation technique as the "market approach" with observable inputs. The Company analyzes available-for-sale securities to determine if losses are other than temporary.

The fair value of the Company’s decommissioning trust funds and investments in debt securities, at December 31, 2011 and 2010, and the level within the three levels of the fair value hierarchy defined by FASB guidance are presented in the table below (in thousands):

Description of Securities	**Fair Value as of December 31, 2011**	**Quoted Prices in Active Markets for Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**
Trading Securities:				
Investments in Debt Securities	$ 1,120	$ —	$ —	$ 1,120
Available for sale:				
U.S. Government Bonds	$ 12,776	$ 12,776	$ —	$ —
Federal Agency Mortgage Backed Securities	26,825	—	26,825	—
Municipal Bonds	37,316	—	37,316	—
Corporate Asset Backed Obligations	12,400	—	12,400	—
Subtotal, Debt Securities	89,317	12,776	76,541	—
Common Stock	74,907	74,907	—	—
Cash and Cash Equivalents	3,739	3,739	—	—
Total available for sale	$ 167,963	$ 91,422	$ 76,541	$ —

Description of Securities	Fair Value as of December 31, 2010	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Trading Securities:				
Investments in Debt Securities	$ 2,909	$ —	$ —	$ 2,909
Available for sale:				
U.S. Government Bonds	$ 20,033	$ 20,033	$ —	$ —
Federal Agency Mortgage Backed Securities	21,204	—	21,204	—
Municipal Bonds	32,541	—	32,541	—
Corporate Asset Backed Obligations	9,077	—	9,077	—
Subtotal, Debt Securities	82,855	20,033	62,822	—
Common Stock	68,016	68,016	—	—
Cash and Cash Equivalents	3,007	3,007	—	—
Total available for sale	$ 153,878	$ 91,056	$ 62,822	$ —

Below is a reconciliation of the beginning and ending balance of the fair value in investment in debt securities (in thousands):

	2011	2010
Balance at January 1	$ 2,909	$ 2,510
Sale of debt security	(2,000)	—
Realized gain on sale of debt security (a)	431	—
Net unrealized gains (losses) in fair value recognized in income on debt securities still held (a)	(220)	399
Balance at December 31	$ 1,120	$ 2,909

(a) These amounts are reflected in the Company's regulatory-basis statement of income as other income.

There were no transfers in and out of Level 1 and Level 2 fair value measurements categories during the twelve month periods ending December 31, 2011 and 2010. There were no purchases, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2011 and 2010.

P. Supplemental Statements of Cash Flows Disclosures

	Years Ended December 31, 2011	2010
	(In thousands)	
Cash paid for:		
Interest on long-term debt and borrowing under the revolving credit facility	$ 48,664	$ 47,783
Income taxes paid (refund), net	(6,260)	7,343
Non-cash financing activities:		
Grants of restricted shares of common stock	3,268	2,098
Issuance of performance shares	628	663
Acquisition of treasury stock for options exercised	500	—

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	5,866,851			(48,620,214)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	97,627			12,680,106
3	Preceding Quarter/Year to Date Changes in Fair Value	5,331,593			
4	Total (lines 2 and 3)	5,429,220			12,680,106
5	Balance of Account 219 at End of Preceding Quarter/Year	11,296,071			(35,940,108)
6	Balance of Account 219 at Beginning of Current Year	11,296,071			(35,940,108)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	1,096,944			(43,913,778)
8	Current Quarter/Year to Date Changes in Fair Value	1,267,732			
9	Total (lines 7 and 8)	2,364,676			(43,913,778)
10	Balance of Account 219 at End of Current Quarter/Year	13,660,747			(79,853,886)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1		(13,815,053)	(56,568,416)		
2		219,844	12,997,577		
3			5,331,593		
4		219,844	18,329,170	92,275,027	110,604,197
5		(13,595,209)	(38,239,246)		
6		(13,595,209)	(38,239,246)		
7		360,827	(42,456,007)		
8		438,929	1,706,661		
9		799,756	(40,749,346)	104,162,168	63,412,822
10		(12,795,453)	(78,988,592)		

Schedule Page: 122(a)(b) Line No.: 1 Column: g

During the first quarter of 2005, the Company entered into treasury rate lock agreements to hedge against potential movements in the treasury reference interest rate pending the issuance of 6% Senior Notes. These treasury rate locks were terminated on May 11, 2005. The treasury rate lock agreements met the criteria for hedge accounting and were designated as a cash flow hedge. In accordance with cash flow hedge accounting, the Company recorded the loss associated with the fair value of the cash flow hedge of approximately $14.5 million, net of tax, as a component of accumulated other comprehensive income. In May 2005, the Company began to recognize in earnings (as additional interest expense) the accumulated other comprehensive income associated with the cash flow hedge. During the next twelve month period, approximately $0.4 million of this accumulated other comprehensive income item will be reclassified to interest expense.

Schedule Page: 122(a)(b) Line No.: 2 Column: e

In accordance with the FERC Guidance Letter related to FASB guidance for employers' accounting for defined benefit pension and other postretirement plans, this amount includes reclassification adjustments of accumulated other comprehensive income as a result of gains or losses, prior service costs or credits and transition assets or obligations related to postretirement benefit plans being recognized as components of net periodic benefit cost of the period.

Schedule Page: 122(a)(b) Line No.: 7 Column: e

In accordance with the FERC Guidance Letter related to FASB guidance for employers' accounting for defined benefit pension and other postretirement plans, this amount includes reclassification adjustments of accumulated other comprehensive income as a result of gains or losses, prior service costs or credits and transition assets or obligations related to postretirement benefit plans being recognized as components of net periodic benefit cost of the period.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	2,947,174,423	2,947,174,423
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	710,303,818	710,303,818
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,657,478,241	3,657,478,241
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	167,393,912	167,393,912
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	3,824,872,153	3,824,872,153
14	Accum Prov for Depr, Amort, & Depl	1,987,897,945	1,987,897,945
15	Net Utility Plant (13 less 14)	1,836,974,208	1,836,974,208
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,955,795,302	1,955,795,302
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	32,102,643	32,102,643
22	Total In Service (18 thru 21)	1,987,897,945	1,987,897,945
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		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,987,897,945	1,987,897,945

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
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					32
					33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)	151,908,641	41,568,183
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	44,206,978	-1,930,921
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	107,701,663	
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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
			3
			4
			5
			6
			7
			8
			9
			10
			11
	20,810,216	172,666,608	12
-37,548,863	20,810,216	59,014,704	13
		113,651,904	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 12 Column: e

Retirement of fully amortized nuclear fuel in connection with the 2011 Units 1 and 2 reloads.

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

Dry cask storage costs allocated to Units 1, 2 and 3.

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

Retirement of fully amortized nuclear fuel in connection with the 2011 Units 1 and 2 reloads.

Schedule Page: 202 Line No.: 14 Column: f

All of the Company’s nuclear fuel financing is accomplished through a trust that has $110 million aggregate principal amount borrowed through senior notes and a $200 million revolving credit facility. The assets and liabilities of the trust are reported on the Company's regulatory basis balance sheets.

The total amount borrowed for nuclear fuel by the trust at December 31, 2011 was $125.3 million of which $15.3 million had been borrowed under the revolving credit facility, and $110 million was borrowed through the senior notes. During 2011, the Company capitalized approximately $5.4 million of costs, including interest on trust borrowings, issuance costs and accrued interest on the senior notes, trustee fees and miscellaneous legal expenses, in connection with the financing of nuclear fuel through the trust. Information on quantities of nuclear fuel materials is not available.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		
4	(303) Miscellaneous Intangible Plant	102,065,996	7,674,372
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	102,065,996	7,674,372
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	291,469	
9	(311) Structures and Improvements	22,565,040	6,286,394
10	(312) Boiler Plant Equipment	115,081,848	47,216,456
11	(313) Engines and Engine-Driven Generators	16,484,210	598,466
12	(314) Turbogenerator Units	142,729,316	97,875,914
13	(315) Accessory Electric Equipment	22,113,505	4,455,296
14	(316) Misc. Power Plant Equipment	42,208,893	23,989,078
15	(317) Asset Retirement Costs for Steam Production	-216,996	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	361,257,285	180,421,604
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,347,703	
19	(321) Structures and Improvements	443,142,733	23,572,470
20	(322) Reactor Plant Equipment	739,988,759	4,010,379
21	(323) Turbogenerator Units	225,131,012	4,222,729
22	(324) Accessory Electric Equipment	169,936,324	234,586
23	(325) Misc. Power Plant Equipment	80,474,125	1,144,541
24	(326) Asset Retirement Costs for Nuclear Production	1,341,529	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,662,362,185	33,184,705
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	10,000	
38	(341) Structures and Improvements	704,767	26,669
39	(342) Fuel Holders, Products, and Accessories	480,893	
40	(343) Prime Movers		
41	(344) Generators	11,182,847	184,728
42	(345) Accessory Electric Equipment	451,417	
43	(346) Misc. Power Plant Equipment	4,033,083	
44	(347) Asset Retirement Costs for Other Production	15,479	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	16,878,486	211,397
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,040,497,956	213,817,706

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	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	11,825,061	
49	(352) Structures and Improvements	6,813,364	-19,857
50	(353) Station Equipment	132,823,704	13,235,767
51	(354) Towers and Fixtures	24,703,940	56,900
52	(355) Poles and Fixtures	81,126,595	5,907,374
53	(356) Overhead Conductors and Devices	74,478,082	1,094,029
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	1,124,916	-29,416
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	332,895,662	20,244,797
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	2,782,089	1,050,668
61	(361) Structures and Improvements	3,827,250	117,566
62	(362) Station Equipment	136,892,539	9,600,537
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	115,961,832	8,228,430
65	(365) Overhead Conductors and Devices	68,110,382	5,248,949
66	(366) Underground Conduit	102,885,620	4,958,433
67	(367) Underground Conductors and Devices	98,755,784	5,886,469
68	(368) Line Transformers	154,153,995	16,317,159
69	(369) Services	39,210,675	1,087,490
70	(370) Meters	35,889,147	2,148,148
71	(371) Installations on Customer Premises	10,199,373	605,782
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	9,760,016	134,439
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	778,428,702	55,384,070
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	899,211	
87	(390) Structures and Improvements	38,682,876	2,949,335
88	(391) Office Furniture and Equipment	27,391,748	3,501,163
89	(392) Transportation Equipment	29,234,067	942,590
90	(393) Stores Equipment	239,072	
91	(394) Tools, Shop and Garage Equipment	2,646,848	120,482
92	(395) Laboratory Equipment	3,282,684	186,698
93	(396) Power Operated Equipment	5,671,326	632,999
94	(397) Communication Equipment	30,957,813	8,528,779
95	(398) Miscellaneous Equipment	2,691,084	657,630
96	SUBTOTAL (Enter Total of lines 86 thru 95)	141,696,729	17,519,676
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	141,696,729	17,519,676
100	TOTAL (Accounts 101 and 106)	3,395,585,045	314,640,621
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)	3,395,585,045	314,640,621

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
					3
14,522			109,725,846		4
14,522			109,725,846		5
					6
					7
			291,469		8
			28,851,434		9
			162,298,304		10
			17,082,676		11
			240,605,230		12
			26,568,801		13
			66,197,971		14
			-216,996		15
			541,678,889		16
					17
			2,347,703		18
3,860,444			462,854,759		19
866,608			743,132,530		20
3,219,309			226,134,432		21
185,450			169,985,460		22
156,686			81,461,980		23
	-41,670,087		-40,328,558		24
8,288,497	-41,670,087		1,645,588,306		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			10,000		37
			731,436		38
			480,893		39
					40
			11,367,575		41
			451,417		42
			4,033,083		43
			15,479		44
			17,089,883		45
8,288,497	-41,670,087		2,204,357,078		46

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
			11,825,061		48
			6,793,507		49
60,337			145,999,134		50
			24,760,840		51
			87,033,969		52
			75,572,111		53
					54
					55
			1,095,500		56
					57
60,337			353,080,122		58
					59
			3,832,757		60
			3,944,816		61
			146,493,076		62
					63
129,103			124,061,159		64
9,204			73,350,127		65
461			107,843,592		66
33,251			104,609,002		67
395,518			170,075,636		68
			40,298,165		69
279,746			37,757,549		70
1,341			10,803,814		71
					72
9,323			9,885,132		73
					74
857,947			832,954,825		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			899,211		86
233,444			41,398,767		87
			30,892,911		88
917,824			29,258,833		89
			239,072		90
			2,767,330		91
			3,469,382		92
2,775			6,301,550		93
701,992			38,784,600		94
			3,348,714		95
1,856,035			157,360,370		96
					97
					98
1,856,035			157,360,370		99
11,077,338	-41,670,087		3,657,478,241		100
					101
					102
					103
11,077,338	-41,670,087		3,657,478,241		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	None				
2					
3					
4					
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6					
7					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	None			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
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16				
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19				
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21	Other Property:			
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45				
46				
47	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	PALO VERDE CAPITAL IMPROVEMENTS	53,821,543
2	RIO GRANDE UNIT 9	37,152,240
3	DISTRIBUTION COMMERCIAL CONSTRUCTION - TX	5,093,499
4	INFORMATION TECHNOLOGY HARDWARE & SOFTWARE PROJECTS	4,635,702
5	DURAZNO SUBSTATION	3,419,140
6	DISTRIBUTION RESIDENTIAL CONSTRUCTION - TX	3,389,132
7	FARMER-ALAMO TRANSMISSION LINE STRUCTURE REPLACEMENT	3,085,269
8	NEWMAN BREAKER REPLACEMENT & UPGRADE	2,975,257
9	PENDALE SUBSTATION	2,827,838
10	TRANSPORTATION EQUIPMENT	2,775,285
11	AUSTIN SUBSTATION REGULATOR REPLACEMENT	2,124,372
12	ORACLE BUSINESS INTELLIGENCE SYSTEM	2,064,707
13	FACILITIES SERVICES STRUCTURAL IMPROVEMENTS	2,056,884
14	SANTA TERESA - MONTOYA TRANSMISSION LINE EXPANSION	2,027,071
15	DISTRIBUTION BETTERMENT - TX	1,979,244
16	DISTRIBUTION WORK MANAGEMENT & GIS SYSTEM UPGRADE	1,878,240
17	SUNSET SUBSTATION UPGRADES	1,847,330
18	WATER TREATMENT SYSTEM - NEWMAN POWER STATION	1,762,393
19	ASCARATE SUBSTATION TRANSFORMER & REGULATOR REPLACEMENT	1,725,035
20	DISTRIBUTION BETTERMENT - NM	1,660,679
21	FOUR CORNERS CAPITAL IMPROVEMENT	1,581,517
22	DISTRIBUTION COMMERCIAL CONSTRUCTION - NM	1,337,357
23	GLOBAL REACH TRANSMISSION LINE	1,116,688
24	NEWMAN UNIT 4 COOLING TOWER & CIRCULATING WATER SYSTEM	1,084,797
25	COPPER TO LANE TRANSMISSION LINE	1,073,537
26	DISTRIBUTION RESIDENTIAL CONSTRUCTION - NM	1,014,439
27	MINOR PROJECTS	21,884,717
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	167,393,912

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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	1,896,356,865	1,896,356,865		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	71,347,992	71,347,992		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-1,078,790	-1,078,790		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	517,873	517,873		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	70,787,075	70,787,075		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	11,077,338	11,077,338		
13	Cost of Removal	1,095,458	1,095,458		
14	Salvage (Credit)	824,158	824,158		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	11,348,638	11,348,638		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,955,795,302	1,955,795,302		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	224,818,717	224,818,717		
21	Nuclear Production	1,171,168,275	1,171,168,275		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	9,708,400	9,708,400		
25	Transmission	190,847,461	190,847,461		
26	Distribution	275,711,509	275,711,509		
27	Regional Transmission and Market Operation				
28	General	83,540,940	83,540,940		
29	TOTAL (Enter Total of lines 20 thru 28)	1,955,795,302	1,955,795,302		

Schedule Page: 219   Line No.: 8   Column: c

Represents Palo Verde depreciation expense adjustment charged to FERC account 182-399, related to NM Rate Cases 06-00258-UT and 09-00171-UT, which ceased in March 2011 with the renewal of the operating licenses for all three units at Palo Verde. The renewed licenses for Units 1, 2, and 3 will now expire in 2045, 2046 and 2047, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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	MiraSol Energy Services, Inc.			
2	Capital Stock:			
3	Common Stock - 1,000 shares authorized, issued and outstanding			
4	No par value	03/01/01		1,000
5				
6	Additional Paid-in Capital	03/01/01		3,852,563
7				
8	Accumulated Deficit			-3,851,799
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 1,810		TOTAL	1,764

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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
		1,000		4
				5
	126	3,852,689		6
				7
-80		-3,851,879		8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
-80	126	1,810		42

Schedule Page: 224 Line No.: 6 Column: f

Represents net change to paid-in-capital during the year.

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)	1,582,462	1,503,621	Production
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)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	23,107,016	26,305,618	Production
8	Transmission Plant (Estimated)	3,823,927	4,622,282	Transmission
9	Distribution Plant (Estimated)	5,976,042	5,877,414	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,572,043	1,879,833	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	34,479,028	38,685,147	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	518		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	36,062,008	40,188,768	

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

Consists primarily of items used in the field and includes conduit, underground rubber goods, lighting and safety supplies and tools.

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

Consists primarily of items used in the field and includes conduit, underground rubber goods, lighting and safety supplies and tools.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.	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	10,059.00		359.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	352.00			
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				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	10,411.00		359.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
359.00		359.00		9,334.00		20,470.00		1
								2
								3
						352.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
359.00		359.00		9,334.00		20,822.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

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

Represents allowances banked by the Company through December 31, 2010.

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

Represents allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework.

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

Represents allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework.

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

Represents allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework.

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

Represents allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework. Proposed allowances for future years include allowances for each year beginning in 2015 and beyond.

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

The Company has not purchased any allowances; however, at December 31, 2011 SO_2 allowances were trading at $0.50 per ton (allowance).

Schedule Page: 228 Line No.: 4 Column: b

Represents (i) 359 allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework and (ii) (7) allowances withheld by the EPA for 2010.

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	-50.00	70,506		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	922.00		885.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Evolution Markets	1,000.00	105,000		
10					
11					
12					
13					
14					
15	Total	1,000.00	105,000		
16					
17	Relinquished During Year:				
18	Charges to Account 509	881.00	61,670		
19	Other:				
20		933.00	80,353		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	58.00	33,483	885.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
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				

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. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						-50.00	70,506	1
								2
								3
						1,807.00		4
								5
								6
								7
								8
						1,000.00	105,000	9
								10
								11
								12
								13
								14
						1,000.00	105,000	15
								16
								17
						881.00	61,670	18
								19
						933.00	80,353	20
								21
								22
								23
								24
								25
								26
								27
								28
						943.00	33,483	29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Schedule Page: 229 Line No.: 18 Column: b

Represents the NOx allowances expected to be purchased for the 2011 compliance year.

Schedule Page: 229 Line No.: 18 Column: c

Represents the accrual related to the NOx allowances expected to be purchased for the 2011 compliance year.

Schedule Page: 229 Line No.: 20 Column: b

Includes an adjustment of (i) 11 NOx allowances to true-up to the 2010 actual shortage and (ii) 922 NOx allowances to reflect the application of the EPA issued emission allowances for 2011.

Schedule Page: 229 Line No.: 20 Column: c

Represents the NOx allowance cost adjustment to true-up to the 2010 actual shortage.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	None					
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Taxes - Regulatory Assets	102,237,170	14,808,993	various	18,922,628	98,123,535
2						
3	Rio Grande Resources Trust:					
4	Nuclear Fuel Postload Daily Finance Charge	2,165,721	3,454,513	518	1,940,611	3,679,623
5						
6	Coal Reclamation	10,282,189		501/431	3,627,333	6,654,856
7						
8	Net Undercollection of Fuel Revenues:					
9	Texas		9,130,052	440s		9,130,052
10						
11	Texas:					
12	2009 Rate Case Cost	3,298,067	128,440	928	2,280,921	1,145,586
13	2012 Rate Case Cost		648,431			648,431
14						
15	Texas Military Base Discount and Recovery	761,275	3,379,345	142	1,614,525	2,526,095
16						
17	Texas Energy Efficiency	5,459,547	5,930,160	142	6,893,148	4,496,559
18						
19	New Mexico Renewable Energy Cost:					
20	Renewable Procurement Plans 2006 and 2008	232,092		407.3	232,092	
21	Renewable Procurement Plan	122,242	17,006			139,248
22	Renewable Energy Credits 2009 and Prior	1,139,184		407.3	1,139,184	
23	Renewable Energy Credits	929,782	1,954,130			2,883,912
24						
25	New Mexico Energy Efficiency Program	321,418	3,182,502	142	3,201,173	302,747
26						
27	New Mexico:					
28	2009 Rate Case Cost	505,511		928	252,648	252,863
29	2010 FPPCAC Audit	1,127	426,143			427,270
30						
31	Palo Verde Deferred Depreciation	4,772,585	517,874	407.3	114,138	5,176,321
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	132,227,910	43,577,589		40,218,401	135,587,098

Schedule Page: 232 Line No.: 1 Column: b

Amortization period ranges from 5 to 40 years.

Schedule Page: 232 Line No.: 4 Column: b

Amortization is based on a pro rata relationship with nuclear fuel amortization.

Schedule Page: 232 Line No.: 6 Column: b

Represents total company final coal mine reclamation liability. Final coal mine reclamation represents the cost to reclaim the land disturbed during the coal mining that was not previously reclaimed while the mine was in operation. Current ongoing reclamation of land is passed through as reconcilable fuel costs. In the Company's New Mexico jurisdiction the recovery of final coal reclamation costs was approved as a base fuel component in Case No. 06-00258-UT and will be amortized through July 2016, the remaining life of the Four Corners generating facility. In the Company's Texas jurisdiction the recovery of final reclamation costs was approved as a component of reconciliable fuel in the Final Order of PUC Docket No. 38361 issued January 27, 2011 to be amortized over a 113 month period beginning March 2007 through July 2016. The Company recorded a cumulative adjustment for the period March 2007 through December 2010 in January 2011. In the Company's FERC jurisdiction final coal reclamation costs will not be recovered until actual final reclamation is paid in the last two years of the mining contract.

Schedule Page: 232 Line No.: 12 Column: b

This balance is related to rate case costs approved in Docket No. 37690 and will be amortized over a 2 year period beginning July 2010.

Schedule Page: 232 Line No.: 15 Column: b

In accordance with the Final Order in Docket No. 37690, a Military Base Rate Discount is available to federal military bases. The Military Base Discount Recovery Factor allows the Company to recover the total base rate discount provided to military base facilities from non-military customers through a recovery factor.

Schedule Page: 232 Line No.: 17 Column: b

In accordance with the Final Order in Docket No. 37690, the Company began recovering Energy Efficiency Program costs effective July 2010, through a tariff rider approved by the PUCT via Texas Rate 97. The rate is updated annually.

Schedule Page: 232 Line No.: 20 Column: b

In accordance with the Final Order in Case No. 09-0071-UT, the Company recovers its renewable energy procurement costs related to renewable energy certificates as a component of base rates and began amortizing such costs over a 2 year period in January 2010.

Schedule Page: 232 Line No.: 21 Column: f

The Company will request these costs as a component of base rates in the Company's next rate case filing.

Schedule Page: 232 Line No.: 22 Column: b

Represents the cost of Renewable Energy Credits purchased by the Company to comply with the Renewable Energy Act ("REA"). The REA authorizes the recovery of reasonable costs of compliance with the REA through the rate making process. The Company requested recovery of these costs as a component of base rates in Case No. 09-00171-UT and began amortizing such costs over a 2 year period in January 2010.

Schedule Page: 232 Line No.: 23 Column: f

The Company will request these costs as a component of base rates in the Company's next rate case filing.

Schedule Page: 232 Line No.: 25 Column: b

In accordance with the Final Order in Docket No. 06-0065-UT, the Company started collecting Energy Efficiency Program costs, effective May 2009, through a tariff rider approved by the NMPRC via New Mexico Rate 17. The rate is updated annually.

Schedule Page: 232 Line No.: 28 Column: b

Represents rate case costs related to Case No. 09-00171-UT and is being amortized over a 3 year period beginning January 2010.

Schedule Page: 232 Line No.: 29 Column: b

Represents costs incurred for a Fuel and Purchased Power Cost Adjustment Clause (FPPCAC) audit. As ordered by the NMPRC in Case No. 09-00171-UT, the Company can defer these costs as a regulatory asset and request recovery in a future rate proceeding after the costs are incurred.

Schedule Page: 232 Line No.: 31 Column: b

In NMPRC Case No. 09-00171-UT the NMPRC extended the depreciable life of Palo Verde an additional 20 years for New Mexico ratemaking purposes, reducing the depreciation expense collected from New Mexico customers in rates, effective January 2010. In April 2011, the NRC renewed the operating license for all three units at Palo Verde for an additional 20 years; therefore, the incremental difference in Palo Verde depreciation for the New Mexico jurisdiction will be amortized to account 407.3 over the remaining life of Palo Verde.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Facility & Impact Study	120,661	433,089	131	935,165	-381,415
2						
3	Miscellaneous	219	110,434	Various	67,395	43,258
4						
5	Reimbursable Transmission &					
6	Distribution Projects	-244,922	1,457,357	416	606,943	605,492
7						
8	El Paso Water Utilities Land					
9	Lease	1,923,361	327,512	507	402,873	1,848,000
10						
11	Palo Verde Water					
12	Agreement Deposit	1,097,191	1,065,751			2,162,942
13						
14						
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16						
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21						
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43						
44						
45						
46						
47	Misc. Work in Progress	-8,277				54,648
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	2,888,233				4,332,925

Schedule Page: 233 Line No.: 9 Column: c

Annual cash payment for land leased adjacent to our Newman Power Plant.

Schedule Page: 233 Line No.: 12 Column: c

In, May 2010, Palo Verde entered into a 40 year Municipal Effluent Purchase and Sale Agreement with the Sub-regional Operating Group (City of Phoenix, City of Mesa, City of Scottsdale and the City of Glendale).

Schedule Page: 233 Line No.: 47 Column: a

Represents CWIP charges pending completion of project, at which time amounts will then be transferred to the proper account.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		247,543,740	247,527,359
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	247,543,740	247,527,359
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	4,462,598	3,135,358
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	252,006,338	250,662,717

Notes

Schedule Page: 234 Line No.: 2 Column: a

< Page 234 Line 2 Column (a) >

	Balance at Beginning of Year	Balance at End of Year
ELECTRIC		
Deferred tax assets:		
Capitalized revenues and other capitalized costs	83,263,895	55,684,906
Benefit of tax loss carryforwards	285,577	21,737,289
Pensions and benefits	58,025,858	84,742,029
Alternative minimum tax credit carryforward	18,370,146	19,862,584
Regulatory liabilities related to income taxes	20,433,457	14,761,658
Asset retirement obligation	33,257,357	21,987,160
Deferred fuel	6,583,859	0
Debt related items	7,448,821	7,227,966
Other	19,874,770	21,523,767
Net deferred tax assets	247,543,740	247,527,359

< Page 234 Line 17 Column (a) >

	Balance at Beginning of Year	Balance at End of Year
OTHER (Specify)		
Deferred tax assets:		
Other capitalized costs	3,085,105	0
Other	1,377,493	3,135,358
Net deferred tax assets	4,462,598	3,135,358
Total Account 190	252,006,338	250,662,717

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	201			
2	Common Stock (1)			
3	New York Stock Exchange (NYSE)	100,000,000	1.00	
4	Total Common Stock (2)	100,000,000		
5				
6	204			
7	Preferred Stock	2,000,000		
8	Total Preferred Stock	2,000,000		
9				
10				
11	(1) As of December 31, 2011 453,358			
12	unissued shares of Common Stock of the			
13	Company were reserved for future			
14	allocations. 402,783 are reserved			
15	under the 1999 Long-Term Incentive Plan			
16	and 50,575 shares are reserved under			
17	the 2007 Long-term Incentive Plan.			
18				
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28	Note: For additional information see the			
29	El Paso Electric Company 2011 Form 10-K			
30	filed with the SEC February 27, 2012.			
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42				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	
						1
						2
65,452,073	65,363,347	25,492,919	424,646,957			3
65,452,073	65,363,347	25,492,919	424,646,957			4
						5
						6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	211. Other Paid-in Capital	
2	Deferred Compensation:	
3	Performance Awards	2,890,546
4	Stock Options	93,864
5		
6		
7		
8		
9		
10		
11		
12		
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14		
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39		
40	TOTAL	2,984,410

Schedule Page: 253 Line No.: 3 Column: b

Represents deferred compensation related to grants of performance share awards to certain officers in 2009, 2010, and 2011 under the Company's existing long-term incentive plans, which provide for the issuance of Company stock based on the achievement of certain performance criteria over a three-year period.

Schedule Page: 253 Line No.: 4 Column: b

In accordance with FASB guidance for accounting for stock-based compensation, the Company began expensing the fair value of outstanding awards for which the requisite service had not been rendered as of January 1, 2006. No compensation cost was recognized in 2011, and there is no remaining unrecognized compensation costs related to stock options.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	214. Capital Stock Expense	340,939
2		
3		
4		
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21		
22	TOTAL	340,939

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	Account 221		
2			
3	2009 Series A Palo Verde Pollution Control Bonds	63,500,000	1,168,950
4	2009 Series B Palo Verde Pollution Control Bonds	37,100,000	811,106
5	2005 Series A Palo Verde Pollution Control Bonds	59,235,000	1,249,815
6	2002 Series A Four Corners Pollution Control Bonds	33,300,000	1,075,004
7			
8	Subtotal	193,135,000	4,304,875
9			
10	Account 222		
11			
12	Subtotal		
13			
14	Account 224		
15			
16	2005 Senior Notes	400,000,000	5,239,886
17			2,312,000 D
18	2008 Senior Notes	150,000,000	1,714,035
19			1,281,000 D
20	Treasury Rate Lock Agreements		
21			
22	Subtotal	550,000,000	10,546,921
23			
24	Interest on obligations under capital lease (Rio Grande Resources Trust II):		
25	$110 million RGRT Senior Notes		
26	Revolving Credit Facility		
27			
28			
29			
30			
31			
32			
33	TOTAL	743,135,000	14,851,796

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
03/26/09	02/01/40	03/26/09	02/01/40	63,500,000	4,603,750	3
03/26/09	04/01/40	03/26/09	04/01/40	37,100,000	2,689,750	4
08/01/05	08/01/40	08/01/05	08/01/40	59,235,000	2,967,674	5
08/01/05	06/01/32	08/01/05	06/01/32	33,300,000	1,446,468	6
						7
				193,135,000	11,707,642	8
						9
						10
						11
						12
						13
						14
						15
05/17/05	05/15/35	05/17/05	05/15/35	400,000,000	24,000,000	16
						17
06/03/08	03/15/38	06/03/08	03/15/38	150,000,000	11,250,000	18
						19
					360,827	20
						21
				550,000,000	35,610,827	22
						23
						24
					5,053,500	25
					260,385	26
						27
						28
						29
						30
						31
						32
				743,135,000	52,632,354	33

Schedule Page: 256 Line No.: 24 Column: a

Rio Grande Resources Trust II is a trust through which the Company finances its portion of nuclear fuel for Palo Verde.

Schedule Page: 256 Line No.: 25 Column: b

Obligations under capital lease-noncurrent are recorded in FERC account 227.

Schedule Page: 256 Line No.: 26 Column: b

Obligations under capital lease-current are recorded in FERC account 243.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	104,162,168
2		
3		
4	Taxable Income Not Reported on Books	
5	(see page 261 footnote)	16,334,812
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	(see page 261 footnote)	54,684,475
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	(see page 261 footnote)	-8,158,595
16		
17	Federal Income Taxes (Detail Below)	51,330,199
18		
19	Deductions on Return Not Charged Against Book Income	
20	(see page 261 footnote)	-275,020,823
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-56,667,764
28	Show Computation of Tax:	
29		
30		
31	Tax computed at statutory rate (see page 261 footnote)	55,127,268
32	ITC Amortization Net of Deferred Taxes	-803,645
33	Amortization of Excess Deferred Taxes	-773,220
34	Permanent Differences	174,065
35		
36	State Income Taxes (Federal Effect)	-704,939
37	Amortization of Regulatory Assets	-432,732
38	Allowance for Equity Funds Used During Construction	-951,358
39	Other	-305,240
40		
41		
42	Total Federal Income Tax Expense	51,330,199
43		
44		

Schedule Page: 261 Line No.: 5 Column: b

Contributions in aid of construction	3,999,999
Capitalized Construction Interest	12,329,293
Las Cruces Settlement	5,520
Taxable Income Not Reported on Books	16,334,812

Schedule Page: 261 Line No.: 10 Column: b

Meals and Entertainment	121,053
Lobbying	923,471
Capitalized A&G	5,131,975
Legal Expense Accrual	(154,977)
Decommissioning Costs	41,904,184
Employee Benefit Plans	3,492,625
Deferred State Taxes and Reserves	(923,536)
Coal Reclamation	3,627,333
Water Utility Lease	75,362
Uncollectible Accounts receivable	130,195
Penalties	116,790
Other	240,000
Deductions Recorded on Books Not Deducted for Return	54,684,475

Schedule Page: 261 Line No.: 15 Column: b

Decommissioning Trust Interest Net of Fees	(857,659)
Unbilled Revenue	192,541
AFUDC	(7,566,997)
Employee Benefit Plans	73,520
Income Reported on Books Not Included in Return	(8,158,595)

Schedule Page: 261 Line No.: 20 Column: b

Debt Costs	(1,217,031)
Employee Benefit Plans	(8,032,788)
Environmental Cost Accrual	(102,021)
Depreciation and Amortization Differences	(184,942,260)
Deferred Fuel	(19,427,213)
FAS 143 ARO	(35,501,436)
Section 174 R&D	(3,999,996)
Project Care Bravo	(6,742,854)
Repair Allowance	(13,000,000)
Taxes Other Than Federal	(1,700,984)
Other	(354,240)
Deductions on Return not Charged Against Book Income	(275,020,823)

Schedule Page: 261 Line No.: 31 Column: b

Net Income	104,162,168
Federal and State Income Tax Expense	53,344,313
Pre-Tax Income	157,506,481
Tax Rate	35%
Tax Computed at Statutory Rate	55,127,268

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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					
2	Current FIT Payable	-800,336	10,298,341	11,843,405	660,000	
3	Prior Years	961,725		-10,009,484	-9,329,738	
4	FUTA			57,243	57,243	
5	Insurance Contributions			5,604,119	5,604,119	
6	Subtotal	161,389	10,298,341	7,495,283	-3,008,376	
7						
8	State County & Local - TX					
9	Ad Valorem	6,096,307		6,954,484	6,168,122	
10	Gross Receipts	1,872,725		10,100,283	10,283,705	
11	Unemployment			199,478	199,478	
12	Franchise Tax / Margin Tax	2,040,004		2,479,621	2,209,587	
13	Use Tax	339,020		3,836,100	3,672,732	
14	Regulatory Commission	509,688		954,559	966,824	
15	Franchise Fees (OSR)	5,698,337	9,796	19,037,768	20,812,466	
16	Subtotal	16,556,081	9,796	43,562,293	44,312,914	
17						
18	State County & Local - NM					
19	Ad Valorem	1,470,516	1,454	2,885,934	2,913,840	
20	Income	-669,379		4,657	200,000	
21	Unemployment			29,815	29,815	
22	Compensating	240,889		1,889,927	1,989,620	
23	Regulatory Commission	913,322		986,662	922,541	
24	Franchise Fees (OSR)	160,012	331,365	3,272,896	3,134,740	
25	L.C. Fran. Pumping Facility					
26	Payroll Taxes			157,769	157,769	
27	Worker's Compensation Fee					
28						
29						
30	Other Taxes	-726		-9,323	-9,323	
31	Subtotal	2,114,634	332,819	9,218,337	9,339,002	
32						
33						
34	State County & Local - AZ					
35	Ad Valorem	3,371,884		6,348,815	6,546,591	
36	Income	669,756	3,408,449	453,371		
37	Palo Verde Payroll Taxes			2,922,701	2,922,701	
38	Sales & Use Taxes			1,346		
39	Subtotal	4,041,640	3,408,449	9,726,233	9,469,292	
40						
41	TOTAL	22,873,744	14,049,405	70,002,146	60,112,832	

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 (I) 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
84,728		12,109,250			-265,845	2
336,903	54,924	-10,335,171			325,687	3
		44,824			12,419	4
		4,388,315			1,215,804	5
421,631	54,924	6,207,218			1,288,065	6
						7
						8
6,882,669		6,893,270			61,214	9
1,689,303		10,624,594			-524,311	10
		156,202			43,276	11
2,310,038		2,479,621				12
502,388					3,836,100	13
497,423		954,559				14
3,923,990	10,147	19,037,768				15
15,805,811	10,147	40,146,014			3,416,279	16
						17
						18
1,443,013	1,857	2,885,966			-32	19
1,145	865,867	-9,440			14,097	20
		23,347			6,468	21
141,196		1,857			1,888,070	22
977,443		986,662				23
186,845	220,042	119,091			3,153,805	24
						25
		157,769				26
						27
						28
						29
-726		15,505			-24,828	30
2,748,916	1,087,766	4,180,757			5,037,580	31
						32
						33
						34
3,174,108		6,348,815				35
114,379	2,399,701	487,760			-34,389	36
		2,922,701				37
1,346					1,346	38
3,289,833	2,399,701	9,759,276			-33,043	39
						40
22,266,191	3,552,538	60,293,265			9,708,881	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%	2,001			411.4	2,001	
3	4%						
4	7%						
5	10%	26,733,030			411.4 / 420.0	1,538,678	
6	30%	-43,524			411.4	-351,411	
7							
8	TOTAL	26,691,507				1,189,268	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10					411.4	1,275,208	
11					420.0	-85,940	
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
25,194,352			5
307,887			6
			7
25,502,239			8
			9
-1,275,208			10
85,940			11
			12
			13
			14
			15
			16
			17
			18
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			28
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			31
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			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Coal Reclamation	11,700,000				11,700,000
2						
3	Transmission Access					
4	PNM	320,277	186	320,277		
5						
6	OPEB					
7	Palo Verde	568,455	131	284,229		284,226
8	Four Corners	709,036	131	22,499		686,537
9						
10	Environmental Accrual	384,096	131/554	79,096		305,000
11						
12	Texas Docket 23530 Settlement	2,413,403	131	176,800	7,360	2,243,963
13						
14	345KV Transmission Line Relocation				3,000,000	3,000,000
15						
16	Other	100,505	131/440s	118,977	151,041	132,569
17						
18						
19						
20						
21						
22						
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42						
43						
44						
45						
46						
47	TOTAL	16,195,772		1,001,878	3,158,401	18,352,295

Schedule Page: 269   Line No.: 14   Column: e

Represents amount received from Union Pacific Railroad to relocate the Diablo-Luna transmission line.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
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)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

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.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
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							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	439,633,890	51,628,871	29,819,121
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	439,633,890	51,628,871	29,819,121
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	439,633,890	51,628,871	29,819,121
10	Classification of TOTAL			
11	Federal Income Tax	439,633,890	51,628,871	29,819,121
12	State Income Tax			
13	Local Income Tax			

NOTES

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
6,165,305	4,470,086			various	6,226,993	469,365,852	2
							3
							4
6,165,305	4,470,086				6,226,993	469,365,852	5
							6
							7
							8
6,165,305	4,470,086				6,226,993	469,365,852	9
							10
6,165,305	4,470,086				6,226,993	469,365,852	11
							12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 2 Column: c

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Plant, principally due to depreciation and basis differences	$ 360,357,251	$ 413,194,396
Regulatory assets related to income taxes	45,162,622	33,873,687
Decommissioning	34,114,017	20,018,626
Deferred fuel	0	2,279,143
Total - Electric Other	$ 439,633,890	$ 469,365,852

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	Deferred Tax	12,489,256	-8,266,341	1,902,059
4				
5	Deferred State Tax	29,320,487		
6				
7	FIT on SIT	27,289,574		
8	Other - Debt	6,511,821		
9	TOTAL Electric (Total of lines 3 thru 8)	75,611,138	-8,266,341	1,902,059
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)	75,611,138	-8,266,341	1,902,059
20	Classification of TOTAL			
21	Federal Income Tax	46,290,651	-8,266,341	1,902,059
22	State Income Tax	29,320,487		
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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
		254.3	5,764,060	182.3	12,115,602	8,672,398	3
							4
		254.3	12,971,737	182.3	14,785,131	31,133,881	5
							6
		254.3	8,233,897	182.3	2,687,262	21,742,939	7
975,508	975,508	254.3	45,535	182.3	27,929	6,494,215	8
975,508	975,508		27,015,229		29,615,924	68,043,433	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
975,508	975,508		27,015,229		29,615,924	68,043,433	19
							20
975,508	975,508		14,043,492		14,830,793	36,909,552	21
			12,971,737		14,785,131	31,133,881	22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Regulatory Tax Liabilities	59,863,742	various	20,003,506	10,482,644	50,342,880
2						
3	Net Overcollection of Fuel Revenues:					
4	Texas	14,205,785	182.3	14,205,785		
5	New Mexico	4,732,897	440s	2,633,074		2,099,823
6	FERC	36,804	440s	31,716		5,088
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
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27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	78,839,228		36,874,081	10,482,644	52,447,791

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	Year/Period of Report 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	315,202,372	289,547,215
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	267,812,171	252,411,047
5	Large (or Ind.) (See Instr. 4)	75,626,551	71,273,263
6	(444) Public Street and Highway Lighting	4,778,012	5,437,255
7	(445) Other Sales to Public Authorities	137,306,045	123,347,332
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	800,725,151	742,016,112
11	(447) Sales for Resale	82,495,288	108,608,473
12	TOTAL Sales of Electricity	883,220,439	850,624,585
13	(Less) (449.1) Provision for Rate Refunds	581,752	
14	TOTAL Revenues Net of Prov. for Refunds	882,638,687	850,624,585
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,313,009	224,157
17	(451) Miscellaneous Service Revenues	4,513,702	1,886,818
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,224,516	2,208,137
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	571,539	298,454
22	(456.1) Revenues from Transmission of Electricity of Others	25,751,838	21,973,254
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	35,374,604	26,590,820
27	TOTAL Electric Operating Revenues	918,013,291	877,215,405

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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 No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
2,633,390	2,508,834	336,219	331,869	2
				3
2,352,218	2,295,537	37,652	36,536	4
1,096,040	1,087,413	50	49	5
25,642	43,190	200	229	6
1,553,923	1,499,199	4,426	4,472	7
				8
				9
7,661,213	7,434,173	378,547	373,155	10
3,358,975	3,461,680	28	25	11
11,020,188	10,895,853	378,575	373,180	12
				13
11,020,188	10,895,853	378,575	373,180	14

Line 12, column (b) includes $ 2,945,000 of unbilled revenues.

Line 12, column (d) includes 47,783 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 11 Column: d

Includes 608,688 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 11 Column: e

Includes 585,311 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 12 Column: d

Includes 608,688 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 12 Column: e

Includes 585,311 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 14 Column: d

Includes 608,688 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 14 Column: e

Includes 585,311 MWhs related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 300 Line No.: 17 Column: b

Below is the detail of Miscellaneous Service Revenues recorded in account 451:

	December 2011
Non Pay Reconnect Charges	1,942,509
Name Change/Cut in Charge	1,011,084
New Service Charges	251,266
Overhead/Underground Connection Charges	204,529
Texas Energy Efficiency Bonus	833,347
Misc Other	270,967
Total	4,513,702

Schedule Page: 300 Line No.: 17 Column: c

Below is the detail of Miscellaneous Service Revenues recorded in account 451:

	December 2010
Non Pay Reconnect Charges	309,549
Field Collection Charges	60,936
Name Change/Cut in Charge	922,562
New Service Charges	149,468
Overhead/Underground Connection Charges	146,157
Texas Energy Efficiency Bonus	83,849
Misc Other	214,297
Total	1,886,818

Schedule Page: 300 Line No.: 21 Column: b

Includes $311,349 related to the Company's 15.8% share of Palo Verde other electric revenues from APS and $260,190 adjustment related to prior periods.

Schedule Page: 300 Line No.: 21 Column: c

Includes $298,454 related to the Company's 15.8% share of Palo Verde other electric revenues from APS.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	(440)					
2	RESIDENTIAL SALES-TX					
3	01 Residential Service	1,938,383	226,407,036	255,416	7,589	0.1168
4	28 Private Area Lighting Service	2,306	365,672	278	8,295	0.1586
5	TXVRE-R Voluntary Renewable		40,300			
6	Deferred Fuel		3,977,460			
7	Unbilled Revenue	12,192	1,037,000			0.0851
8	Renewable Energy Credit		-40,383			
9						
10	RESIDENTIAL SALES-NM					
11	01 Residential Service	673,310	81,505,423	80,169	8,399	0.1211
12	12 Private Area Lighting Service	2,541	587,249	356	7,138	0.2311
13	Deferred Fuel		976,863			
14	Unbilled Revenue	4,658	349,000			0.0749
15	Renewable Energy Credit		-3,248			
16	Total (440)	2,633,390	315,202,372	336,219	7,832	0.1197
17						
18	(442)					
19	C & I SALES SMALL-TX					
20	02 Small Commercial Service	253,486	38,234,004	22,365	11,334	0.1508
21	07 Outdoor Recreational Lighting	358	40,129	17	21,059	0.1121
22	22 Irrigation Service	1,771	236,478	48	36,896	0.1335
23	24 General Service	1,343,342	142,401,188	5,566	241,348	0.1060
24	25 Large Power Service	200,565	19,114,525	50	4,011,300	0.0953
25	28 Private Area Lighting Service	13,944	1,848,971	403	34,600	0.1326
26	34 Cotton Gin Service	2,077	172,978	2	1,038,500	0.0833
27	TXVRE-C Voluntary Renewable		1,538			
28	Deferred Fuel		3,500,604			
29	Unbilled Revenue	8,212	588,000			0.0716
30	Renewable Energy Credit		-2,040			
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	7,613,430	797,780,151	378,547	20,112	0.1048
42	Total Unbilled Rev.(See Instr. 6)	47,783	2,945,000	0	0	0.0616
43	TOTAL	7,661,213	800,725,151	378,547	20,238	0.1045

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	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	C & I SALES SMALL-NM					
2	03 Small Commercial Service	172,924	23,951,928	7,993	21,634	0.1385
3	04 General Service	264,471	27,276,358	478	553,287	0.1031
4	05 Irrigation Service	52,448	5,878,801	611	85,840	0.1121
5	08 Municipal Water Pumping	2,625	249,397	24	109,375	0.0950
6	09 Large Power Service	24,257	2,223,051	4	6,064,250	0.0916
7	12 Private Area Lighting Service	1,940	441,072	67	28,955	0.2274
8	19 Seasonal Agr. Processing Svc.	3,254	451,172	10	325,400	0.1387
9	25 Outdoor Recreational Lighting	109	15,950	12	9,083	0.1463
10	29 Interrupt. Svc. for Lg Power	4,238	195,713	2	2,119,000	0.0462
11	Deferred Fuel		808,648			
12	Unbilled Revenue	2,197	198,000			0.0901
13	Renewable Energy Credit		-14,294			
14						
15						
16	C & I SALES LARGE-TX					
17	15 Electrolytic Refining	52,491	3,873,915	1	52,491,000	0.0738
18	25 Large Power Service	335,010	31,499,125	36	9,305,833	0.0940
19	26 Petroleum Refinery Service	314,935	20,883,488	1	314,935,000	0.0663
20	28 Private Area Lighting Service	210	26,347			0.1255
21	30 Electric Furnace	24,193	1,878,013	1	24,193,000	0.0776
22	38 Interrupt. Svc. for Lg Power	292,932	10,317,726	5	58,586,400	0.0352
23	Deferred Fuel		1,745,491			
24	Unbilled Revenue	11,384	303,000			0.0266
25						
26	C & I SALES LARGE-NM					
27	09 Large Power Service	39,350	3,648,703	2	19,675,000	0.0927
28	29 Interrupt. Svc. for Lg Power	24,795	1,317,644	4	6,198,750	0.0531
29	Deferred Fuel		116,099			
30	Unbilled Revenue	740	17,000			0.0230
31	Total (442)	3,448,258	343,438,722	37,702	91,461	0.0996
32						
33						
34	(444)					
35	PUBLIC ST. & HIGHWAY LIGHT-TX					
36	08 Gov't Street Lights and Signal	22,126	4,155,194	182	121,571	0.1878
37	Deferred Fuel		42,682			
38	Unbilled Revenue	222	20,000			0.0901
39						
40	PUBLIC ST. & HIGHWAY LIGHT-NM					
41	TOTAL Billed	7,613,430	797,780,151	378,547	20,112	0.1048
42	Total Unbilled Rev.(See Instr. 6)	47,783	2,945,000	0	0	0.0616
43	TOTAL	7,661,213	800,725,151	378,547	20,238	0.1045

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.
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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	11 Municipal St. Lighting and Sig	3,275	551,700	18	181,944	0.1685
2	Deferred Fuel		6,436			
3	Unbilled Revenue	19	2,000			0.1053
4	Total (444)	25,642	4,778,012	200	128,210	0.1863
5						
6	(445)					
7	OTHER SALES PUB AUTH-TX					
8	01 Residential Service	1,295	152,386	227	5,705	0.1177
9	02 Small Commercial Service	8,159	1,210,629	924	8,830	0.1484
10	07 Outdoor Recreational Lighting	5,025	549,918	167	30,090	0.1094
11	11 Municipal Pumping Service	155,904	12,408,566	384	406,000	0.0796
12	22 Irrigation	1,661	210,639	12	138,417	0.1268
13	24 General Service	122,017	13,136,430	356	342,744	0.1077
14	25 Large Power Service	60,748	5,544,170	9	6,749,778	0.0913
15	28 Private Area Lighting	9,563	1,193,753	126	75,897	0.1248
16	31 Military Reservation Service	339,896	25,448,206	1	339,896,000	0.0749
17	38 Interruptible Service Large Po	34,784	1,285,802	1	34,784,000	0.0370
18	41 City and County Service	308,888	31,723,226	935	330,361	0.1027
19	43 University Service	62,719	4,189,735	2	31,359,500	0.0668
20	45 Supplemental Power	20,637	1,640,432	1	20,637,000	0.0795
21	Deferred Fuel		1,986,026			
22	Unbilled Revenue	3,602	304,000			0.0844
23	University Discount		-356,097			
24						
25	OTHER SALES PUB AUTH-NM					
26	01 Residential Service	108	13,070	17	6,353	0.1210
27	03 Small Commercial Service	4,158	645,858	210	19,800	0.1553
28	04 General Service	21,896	2,274,879	38	576,211	0.1039
29	05 Irrigation Service	148	17,623	5	29,600	0.1191
30	07 City and County Service	71,232	8,438,861	824	86,447	0.1185
31	08 Municipal Pumping Service	29,190	2,712,550	130	224,538	0.0929
32	09 Large Power Service	56,281	4,771,196	5	11,256,200	0.0848
33	10 Military Research & Dev. Power	184,152	13,116,787	2	92,076,000	0.0712
34	12 Private Area Lighting	333	71,973	30	11,100	0.2161
35	25 Outdoor Recreational Lighting	554	72,506	19	29,158	0.1309
36	26 State University Service	46,416	3,654,562	1	46,416,000	0.0787
37	Deferred Fuel		725,029			
38	Unbilled Revenue	4,557	127,000			0.0279
39	Renewable Energy Credit		36,330			
40	Total (445)	1,553,923	137,306,045	4,426	351,090	0.0884
41	TOTAL Billed	7,613,430	797,780,151	378,547	20,112	0.1048
42	Total Unbilled Rev.(See Instr. 6)	47,783	2,945,000	0	0	0.0616
43	TOTAL	7,661,213	800,725,151	378,547	20,238	0.1045

Schedule Page: 304 Line No.: 1 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(440) RESIDENTIAL SALES

TEXAS

01 Residential Service	$ 51,061,816
28 Private Area Lighting Service	60,717
Deferred fuel	3,977,460
Total - Texas	55,099,993

NEW MEXICO

01 Residential Service	(4,652,949)
12 Private Area Lighting Service	(19,043)
Deferred Fuel	976,863
Total – New Mexico	(3,695,129)
Total (440)	$ 51,404,864

Schedule Page: 304 Line No.: 1 Column: d

There were less than 44 duplicate customers for all rate schedules combined in 2011.

Schedule Page: 304 Line No.: 18 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(442) COMMERCIAL AND INDUSTRIAL SALES

SMALL - TEXAS

02 Small Commercial Service	$ 6,748,828
07 Outdoor Recreational Lighting	9,429
22 Irrigation Service	50,063
24 General Service	35,427,707
25 Large Power Service	5,188,084
28 Private Area Lighting Service	367,016
34 Cotton Gin Service	55,986
Deferred Fuel	3,500,604
Total - Texas	51,347,717

SMALL - NEW MEXICO

03 Small Commercial Service	(1,230,386)
04 General Service	(1,757,840)
05 Irrigation Service	(263,680)
08 Municipal Water Pumping	(18,018)
09 Large Power Service	(184,672)
12 Private Area Lighting Service	(14,539)
19 Seasonal Agr. Processing Svc.	(21,111)
25 Outdoor Recreational Lighting	(636)
29 Interruptible Service Large Power	(38,372)
Deferred Fuel	808,648
Total – New Mexico	(2,720,606)

LARGE - TEXAS

15 Electrolytic Refining	1,321,437
25 Large Power Service	8,740,781
26 Petroleum Refinery Service	7,924,130
28 Private area Lighting Service	5,516
30 Electric Furnace	608,650
38 Interruptible Svc. for Large Power	7,409,013
Deferred Fuel	1,745,491
Total - Texas	27,755,018

LARGE - NEW MEXICO

09 Large Power Service	(273,186)
29 Interruptible Service Large Power	(164,046)
Deferred Fuel	116,099
Total – New Mexico	(321,133)
Total (442)	$ 76,060,996

Schedule Page: 304.1 Line No.: 34 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(444) PUBLIC STREET AND HIGHWAY LIGHTING

TEXAS

08 Municipal St. Lights & Signals	$ 499,340
Deferred Fuel	42,682
Total – Texas	542,022

NEW MEXICO

11 Municipal St. Lights & Signals	(24,713)
Deferred Fuel	6,436
Total – New Mexico	(18,277)
Total (444)	$ 523,745

Schedule Page: 304.2 Line No.: 6 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(445) OTHER SALES TO PUBLIC AUTHORITIES

TEXAS

01 Residential Service	$ 33,062
02 Small Commercial Service	213,768
07 Outdoor Rec. Lighting Service	132,707
11 Municipal Pumping Service	4,069,224
22 Irrigation	43,587
24 General Service	3,249,216
25 Large Power Service	1,591,185
28 Private Area Lighting	251,800
31 Military Reservation Service	8,552,551
38 Interruptible Service for Large	891,547
41 City and County Service	8,230,105
43 University Service	1,623,179
45 Supplemental Power	533,194
Deferred Fuel	1,986,026
Total – Texas	31,401,151

NEW MEXICO

01 Residential Service	(858)
03 Small Commercial Service	(31,739)
04 General Service	(127,393)
05 Irrigation Service	(638)
07 City and County Service	(526,652)
08 Municipal Pumping	(199,461)
09 Large Power Service	(404,544)
10 Military Research & Dev. Power	(1,218,100)
12 Private Area Lighting	(2,515)
25 Outdoor Rec. Lighting Service	(3,086)
26 State University Service	(285,717)
Deferred Fuel	725,029
Total – New Mexico	(2,075,674)
Total (445)	$ 29,325,477

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Classifi-cation	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	Rio Grande Electric Cooperative	RQ	18	8.0	14.0	11.9
2	Rio Grande Electric Cooperative	AD	18			
3	Arizona Electric Power Cooperative, Inc	SF	1			
4	Arizona Public Service Company	SF	1			
5	Barclays Bank PLC	SF	1			
6	Black Hills Power Inc	SF	1			
7	BNP Paribas Energy Trading GP	SF	1			
8	BP Energy Company	SF	1			
9	Cargill Power Markets, LLC	SF	1			
10	Citigroup Energy Inc.	SF	1			
11	City of Burbank California	SF	1			
12	Comision Federal De Electricidad	OS	N/A			
13	Constellation Energy Commodities Group	SF	1			
14	DB Energy Trading LLC	SF	1			
	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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.

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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	EDF Trading North America, LLC	SF	1			
2	Freeport-MCMoran Copper & Gold Energy	LU	2			
3	Gila River Power LLC	OS	1			
4	Gila River Power LLC	SF	1			
5	Iberdrola Renewables, Inc.	SF	1			
6	Idaho Power Company	SF	1			
7	Imperial Irrigation District	SF	1			
8	J.P. Morgan Ventures Energy Corporation	SF	1			
9	Los Alamos County	OS	1			
10	Los Alamos County	SF	1			
11	Los Angeles Department of Water and Pow	SF	1			
12	Macquarie Energy LLC	SF	1			
13	Merrill Lynch Commodities Inc	SF	1			
14	Morgan Stanley Capital Group, Inc.	SF	1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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).
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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 designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Noble Americas Gas and Power Corp	SF	1			
2	PacifiCorp	SF	1			
3	Powerex Corp.	SF	1			
4	PP&L EnergyPlus Co.	SF	1			
5	Public Service Company of Colorado	SF	1			
6	Public Service Company of New Mexico	OS	1			
7	Public Service Company of New Mexico	SF	1			
8	Salt River Project Agricultural Improv	SF	1			
9	Shell Energy North America (US), LP.	SF	2			
10	Southwestern Public Service Company	SF	1			
11	TransAlta Energy Marketing (U.S.), Inc.	AD	1			
12	TransAlta Energy Marketing (U.S.), Inc.	SF	1			
13	Tri-State G & T Association, Inc	SF	1			
14	Tucson Electric Power Marketing	OS	1			
	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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tucson Electric Power Marketing	SF	1			
2	UNS Electric Inc	SF	1			
3	Westar Energy, Inc.	SF	1			
4	Arizona Electric Power Cooperative, Inc	SF	104			
5	Arizona Public Service Company	SF	104			
6	Eagle	SF	104			
7	HGMA	SF	104			
8	Los Alamos	SF	104			
9	Panda Gila River	SF	104			
10	Public Service Company of New Mexico	SF	104			
11	Salt River Project	SF	104			
12	South West Transmission Co-Op	SF	104			
13	Tucson Electric Power Company	SF	104			
14	Tri-State	SF	104			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
62,656	1,894,768	1,966,635	31,716	3,893,119	1
			-38,856	-38,856	2
27,767		600,804		600,804	3
23,177		504,614	321	504,935	4
11,434		351,126		351,126	5
256		7,125		7,125	6
29,625		964,555	95	964,650	7
12,750		218,080		218,080	8
114,305		3,011,161		3,011,161	9
241,094		6,831,337	3,139	6,834,476	10
22,200		483,932		483,932	11
56,044		3,591,752	296,833	3,888,585	12
85,313		2,177,895	4,632	2,182,527	13
42,625		1,274,218		1,274,218	14
62,656	1,894,768	1,966,635	31,716	3,893,119	
3,296,319	0	78,019,337	582,832	78,602,169	
3,358,975	**1,894,768**	**79,985,972**	**614,548**	**82,495,288**	

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.
87,068		2,420,595		2,420,595	1
608,688		1,247,810		1,247,810	2
			1,784	1,784	3
37,730		837,125	1,265	838,390	4
17,600		628,697	3,183	631,880	5
537		8,000		8,000	6
5,320		146,120		146,120	7
52,732		767,927		767,927	8
			167,978	167,978	9
48		2,675		2,675	10
16,210		430,021		430,021	11
87,695		2,155,895	3,846	2,159,741	12
23,975		589,976		589,976	13
218,681		5,485,888	7,447	5,493,335	14
62,656	1,894,768	1,966,635	31,716	3,893,119	
3,296,319	0	78,019,337	582,832	78,602,169	
3,358,975	**1,894,768**	**79,985,972**	**614,548**	**82,495,288**	

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.
1,000		22,500		22,500	1
8,797		258,337		258,337	2
48,514		765,143	37	765,180	3
2,000		77,800		77,800	4
2,816		113,184		113,184	5
			96,145	96,145	6
24,661		714,708		714,708	7
364,508		11,584,104	1,750	11,585,854	8
841,870		25,332,466	6,572	25,339,038	9
22,571		708,692	18,931	727,623	10
50			1,200	1,200	11
50,313		1,242,784		1,242,784	12
1,704		41,677		41,677	13
			375	375	14
62,656	1,894,768	1,966,635	31,716	3,893,119	
3,296,319	0	78,019,337	582,832	78,602,169	
3,358,975	**1,894,768**	**79,985,972**	**614,548**	**82,495,288**	

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.
98,076		2,197,516	2,965	2,200,481	1
2,220		66,910		66,910	2
1,150		25,200		25,200	3
546		22,698		22,698	4
43		1,637	1,251	2,888	5
70		2,523		2,523	6
85		3,758		3,758	7
			624	624	8
396		16,039	173	16,212	9
621		25,473	815	26,288	10
666		27,496		27,496	11
			327	327	12
392		15,588		15,588	13
376		15,776		15,776	14
62,656	1,894,768	1,966,635	31,716	3,893,119	
3,296,319	0	78,019,337	582,832	78,602,169	
3,358,975	**1,894,768**	**79,985,972**	**614,548**	**82,495,288**	

Schedule Page: 310 Line No.: 1 Column: c
Contract effective April 1, 2008.

Schedule Page: 310 Line No.: 2 Column: b
Prior year adjustment.

Schedule Page: 310 Line No.: 2 Column: c
Contract effective April 1, 2008.

Schedule Page: 310 Line No.: 2 Column: j
Prior year adjustment.

Schedule Page: 310 Line No.: 3 Column: c
1: WSPP Agreement-Rate Schedule FERC No. 6.

Schedule Page: 310 Line No.: 4 Column: j
Transmission services.

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

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

Schedule Page: 310 Line No.: 12 Column: b
Non-firm energy sales.

Schedule Page: 310 Line No.: 12 Column: j
Transmission and ancillary services.

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

Schedule Page: 310.1 Line No.: 3 Column: b
Spinning reserves.

Schedule Page: 310.1 Line No.: 3 Column: j
Spinning reserves.

Schedule Page: 310.1 Line No.: 4 Column: j
Transmission services.

Schedule Page: 310.1 Line No.: 5 Column: j
Transmission services.

Schedule Page: 310.1 Line No.: 9 Column: b
Spinning reserves.

Schedule Page: 310.1 Line No.: 9 Column: j
Spinning reserves.

Schedule Page: 310.1 Line No.: 12 Column: j
Transmission services.

Schedule Page: 310.1 Line No.: 14 Column: j
Transmission services.

Schedule Page: 310.2 Line No.: 3 Column: j
Transmission services.

Schedule Page: 310.2 Line No.: 6 Column: b
Spinning reserves.

Schedule Page: 310.2 Line No.: 6 Column: j
Spinning reserves.

Schedule Page: 310.2 Line No.: 8 Column: j
Transmission services.

Schedule Page: 310.2 Line No.: 9 Column: j
Transmission services.

Schedule Page: 310.2 Line No.: 10 Column: j
Transmission services.

Schedule Page: 310.2 Line No.: 11 Column: b
Prior year adjustment.

Schedule Page: 310.2 Line No.: 11 Column: j
Prior year adjustment.

Schedule Page: 310.2 Line No.: 14 Column: b

Spinning reserves.

Schedule Page: 310.2 Line No.: 14 Column: j

Spinning reserves.

Schedule Page: 310.3 Line No.: 1 Column: j

Transmission services.

Schedule Page: 310.3 Line No.: 5 Column: j

Other Charges are for SRSG penalty received.

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

Other Charges are for SRSG penalty received.

Schedule Page: 310.3 Line No.: 9 Column: j

Other Charges are for SRSG penalty received.

Schedule Page: 310.3 Line No.: 10 Column: j

Other Charges are for SRSG penalty received.

Schedule Page: 310.3 Line No.: 12 Column: j

Other Charges are for SRSG penalty received.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	2,333,830	1,951,850
5	(501) Fuel	176,480,323	163,130,861
6	(502) Steam Expenses	4,061,992	3,707,097
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,465,522	2,296,351
10	(506) Miscellaneous Steam Power Expenses	4,716,757	6,400,323
11	(507) Rents	1,422,512	1,455,764
12	(509) Allowances	142,023	340,375
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	191,622,959	179,282,621
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,701,893	1,592,910
16	(511) Maintenance of Structures	1,133,160	1,325,505
17	(512) Maintenance of Boiler Plant	10,434,297	6,373,202
18	(513) Maintenance of Electric Plant	8,702,408	6,486,955
19	(514) Maintenance of Miscellaneous Steam Plant	2,116,164	1,600,636
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,087,922	17,379,208
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	215,710,881	196,661,829
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	12,884,201	12,420,240
25	(518) Fuel	44,118,186	35,326,817
26	(519) Coolants and Water	5,890,634	5,477,286
27	(520) Steam Expenses	5,741,310	5,863,040
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	3,666,805	6,063,558
31	(524) Miscellaneous Nuclear Power Expenses	19,511,705	18,709,589
32	(525) Rents	87,698	82,494
33	TOTAL Operation (Enter Total of lines 24 thru 32)	91,900,539	83,943,024
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	4,998,318	5,692,233
36	(529) Maintenance of Structures	1,657,811	1,783,923
37	(530) Maintenance of Reactor Plant Equipment	7,454,367	8,155,071
38	(531) Maintenance of Electric Plant	8,401,683	8,066,853
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,737,833	3,391,791
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	25,250,012	27,089,871
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	117,150,551	111,032,895
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)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	29,566	30,808
63	(547) Fuel	3,053,028	1,447,506
64	(548) Generation Expenses		10,211
65	(549) Miscellaneous Other Power Generation Expenses	101,535	14,337
66	(550) Rents	31	6,403
67	TOTAL Operation (Enter Total of lines 62 thru 66)	3,184,160	1,509,265
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,151	1,158
70	(552) Maintenance of Structures	23,508	9,366
71	(553) Maintenance of Generating and Electric Plant	183,296	325,962
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	-56,926	27,294
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	151,029	363,780
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	3,335,189	1,873,045
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	75,149,296	91,916,351
77	(556) System Control and Load Dispatching	1,183,787	1,285,368
78	(557) Other Expenses	96,900	730,956
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	76,429,983	93,932,675
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	412,626,604	403,500,444
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	837,195	733,120
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	126,147	101,333
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	547,381	488,705
87	(561.3) Load Dispatch-Transmission Service and Scheduling	513,648	473,797
88	(561.4) Scheduling, System Control and Dispatch Services	766,895	656,471
89	(561.5) Reliability, Planning and Standards Development	720,169	620,128
90	(561.6) Transmission Service Studies	279	
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	208,675	120,676
94	(563) Overhead Lines Expenses	238,784	128,083
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,577,553	5,804,002
97	(566) Miscellaneous Transmission Expenses	4,528,475	4,268,906
98	(567) Rents	338,509	129,206
99	TOTAL Operation (Enter Total of lines 83 thru 98)	15,403,710	13,524,427
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	27,448	20,573
102	(569) Maintenance of Structures	26,188	38,420
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	593,942	701,699
108	(571) Maintenance of Overhead Lines	1,418,604	1,321,038
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	-30,695	231,339
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,035,487	2,313,069
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	17,439,197	15,837,496

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)
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	650,245	694,645
135	(581) Load Dispatching		
136	(582) Station Expenses	1,353,380	1,106,540
137	(583) Overhead Line Expenses	763,408	868,271
138	(584) Underground Line Expenses	203,067	262,509
139	(585) Street Lighting and Signal System Expenses	816,615	1,021,441
140	(586) Meter Expenses	1,746,079	2,607,494
141	(587) Customer Installations Expenses	450,517	563,567
142	(588) Miscellaneous Expenses	7,446,951	6,607,196
143	(589) Rents	421,847	341,135
144	TOTAL Operation (Enter Total of lines 134 thru 143)	13,852,109	14,072,798
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	25,330	41,036
147	(591) Maintenance of Structures		880
148	(592) Maintenance of Station Equipment	865,573	696,917
149	(593) Maintenance of Overhead Lines	3,985,582	3,620,685
150	(594) Maintenance of Underground Lines	454,331	433,181
151	(595) Maintenance of Line Transformers	1,677	1,289
152	(596) Maintenance of Street Lighting and Signal Systems	184,382	138,332
153	(597) Maintenance of Meters	108,552	23,362
154	(598) Maintenance of Miscellaneous Distribution Plant	364,495	341,296
155	TOTAL Maintenance (Total of lines 146 thru 154)	5,989,922	5,296,978
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	19,842,031	19,369,776
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		139,017
160	(902) Meter Reading Expenses	3,329,612	2,649,404
161	(903) Customer Records and Collection Expenses	11,985,110	10,799,693
162	(904) Uncollectible Accounts	6,207,463	4,816,852
163	(905) Miscellaneous Customer Accounts Expenses	442,857	1,164,138
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	21,965,042	19,569,104

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	619,221	456,361
169	(909) Informational and Instructional Expenses	210,995	
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	830,216	456,361
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	23,428,660	21,682,771
182	(921) Office Supplies and Expenses	4,925,693	4,508,317
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	15,698,914	13,273,000
185	(924) Property Insurance	2,366,903	1,682,583
186	(925) Injuries and Damages	4,477,454	4,079,658
187	(926) Employee Pensions and Benefits	35,713,358	35,404,788
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,718,590	5,834,762
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,258,036	1,452,228
192	(930.2) Miscellaneous General Expenses	14,520,109	14,340,344
193	(931) Rents	452,676	473,958
194	TOTAL Operation (Enter Total of lines 181 thru 193)	109,560,393	102,732,409
195	Maintenance		
196	(935) Maintenance of General Plant	4,577,258	4,380,092
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	114,137,651	107,112,501
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	586,840,741	565,845,682

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Electric Power COOP	SF	1			
2	Arizona Public Service Company	SF	1			
3	Barclays Bank PLC	SF	1			
4	Black Hills Power, Inc.	SF	1			
5	BNP Paribas Energy Trading GP	SF	1			
6	BP Energy Co.	SF	1			
7	Cargill Power Markets, LLC	SF	1			
8	Citigroup Energy Inc.	SF	1			
9	City of Burbank Water & Power	SF	1			
10	Constellation Energy Commodities Group	SF	1			
11	DB Energy Trading, LLC	SF	1			
12	EDF Trading North America, LLC	SF	1			
13	Four Peaks Energy Inc.	OS	1			
14	Freeport-McMoran Copper & Gold Energy	LU	2			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Gila River Power, L.P.	SF	1			
2	Gila River Power, L.P.	OS	1			
3	Hatch Solar Energy Center LLC	OS	1			
4	Iberdrola Renewables, Inc	SF	1			
5	Imperial Irrigation District	SF	1			
6	J.P. Morgan Ventures Energy Corp	SF	1			
7	Los Alamos County	SF	1			
8	Los Angeles Dept of Water and Power	SF	1			
9	Los Angeles Dept of Water and Power	OS	1			
10	Macquarie Cook Power Inc.	SF	1			
11	Macquarie Cook Power Inc.	AD	1			
12	Merrill Lynch Commodities, Inc	SF	1			
13	Morgan Stanley Capital Group, Inc.	SF	1			
14	NRG Solar Roadrunner, LLC	OS	1			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	PacifiCorp	SF	1			
2	PowerEx Corp.	SF	1			
3	Public Service Company of Colorado	SF	1			
4	Public Service Company of Colorado	AD	1			
5	Public Service Company of New Mexico	SF	1			
6	Public Service Company of New Mexico	OS	1			
7	Salt River Project Agricultural Improv	SF	1			
8	Salt River Project Agricultural Improv	OS	1			
9	Shell Energy North America (U.S.), L.P	SF	2	40	40	40
10	Shell Energy North America (U.S.), L.P	OS	1			
11	Shell Energy North America (U.S.), L.P	AD	2			
12	Southwest Environmental Center	OS	1			
13	Southwestern Public Service Company	SF	1			
14	Tenaska Power Service CO	SF	1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Transalta Energy Marketing (U.S.) Inc.	SF	1			
2	Tri-State G & T Power Association Inc.	SF	1			
3	Tucson Electric Power Marketing	SF	1			
4	Tucson Electric Power Marketing	OS	1			
5	UNS Electric, INC.	SF	1			
6	Westar Energy	SF	1			
7	Arizona Electric Power Cooperative	SF	104			
8	Arizona Public Service Company	SF	104			
9	Arlington Valley LLC	SF	104			
10	Dynergy Power	SF	104			
11	Farmington	SF	104			
12	HGMA	SF	104			
13	IID	SF	104			
14	Los Alamos	SF	104			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Panda Gila River	SF	104			
2	Public Service Company	SF	104			
3	Salt River Project	SF	104			
4	Tucson Electric Power Company	SF	104			
5	Tri-State	SF	104			
6	Western Area Power Administration	SF	104			
7	Arizona Electric Power Cooperative	EX	01			
8	Arizona Public Service Company	EX	53			
9	Arizona Public Service Co. (Start-Up)	EX	53			
10	Public Service Company of New Mexico	EX	01			
11	Coral Power	EX	01			
12	Salt River Project	EX	01			
13	Tri-State G&T Association, Inc.	EX	01			
14	Tucson Electric Power Company	EX	01			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Western Area Power Administration	EX	01			
2	Enron Power Marketing, Inc.	AD	2			
3	Inadvertent					
4	NM Net Mtr PP	OS	16			
5	NM Net Mrt RECs	OS	33			
6	TX Non-Firm PP	OS	48			
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES 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.
237				9,207		9,207	1
40,625				1,145,425		1,145,425	2
6,070				231,000		231,000	3
14,440				490,924		490,924	4
19,300				386,890		386,890	5
8,800				248,100		248,100	6
48,264				1,413,180		1,413,180	7
59,904				1,962,956		1,962,956	8
1,212				43,010		43,010	9
11,834				440,799		440,799	10
46,183				1,390,254		1,390,254	11
104,756				3,247,684		3,247,684	12
240				10,457	4,766	15,223	13
608,688							14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

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.
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7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11,149				447,274		447,274	1
					750	750	2
5,098				590,217		590,217	3
4,039				167,817		167,817	4
1,367				47,739		47,739	5
29,919				1,314,757		1,314,757	6
19				760		760	7
2,928				139,727		139,727	8
					160,216	160,216	9
31,192				846,836		846,836	10
19					782	782	11
24,400				640,500		640,500	12
94,890				3,147,293		3,147,293	13
18,367				2,079,446		2,079,446	14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

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)	
38,790				1,105,636		1,105,636	1
31,132				1,491,030		1,491,030	2
1,694				86,542		86,542	3
-19					-760	-760	4
61,399				3,169,617		3,169,617	5
					420	420	6
342,894				11,771,537		11,771,537	7
					4,758	4,758	8
824,406			1,536,000	24,050,598		25,586,598	9
29,600				1,510,095		1,510,095	10
50					1,150	1,150	11
10				1,245		1,245	12
80,152				5,430,761		5,430,761	13
186				8,206		8,206	14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	Year/Period of Report 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.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
8,702				320,328		320,328	1
54,103				2,060,174		2,060,174	2
25,951				932,476		932,476	3
3,223				107,418	580	107,998	4
75				2,625		2,625	5
13,516				867,808		867,808	6
166				5,543		5,543	7
160				5,013		5,013	8
5				450		450	9
					2,167	2,167	10
41				1,819		1,819	11
10				504	2,368	2,872	12
					1,952	1,952	13
6				437		437	14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
17				897		897	1
105				5,342	3,263	8,605	2
238				7,422		7,422	3
325				14,479		14,479	4
23				1,322		1,322	5
130							6
	736						7
		146					8
		744					9
	4,221						10
	2,336						11
		10,683					12
	18,824						13
	22,245						14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

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.

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5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
	437						1
					-312,471	-312,471	2
	5,084	32,517					3
232					11,388	11,388	4
					327,442	327,442	5
229					2,949	2,949	6
							7
							8
							9
							10
							11
							12
							13
							14
2,711,491	53,883	44,090	1,536,000	73,401,576	211,720	75,149,296	

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

Interconnection Agreement and Contract for Power Service between El Paso Electric Company and Four Peaks Energy, Inc. Contract is an evergreen contract.

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

Payment of charges related to New Mexico Public Regulatory Commission (NMPRC) Final Order No. 09-00259-UT.

Schedule Page: 326 Line No.: 14 Column: g

The 608,688 MWhs relate to purchases from Freeport-McMoran Copper & Gold Energy Services LLC ("Freeport") related to El Paso Electric's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 326.1 Line No.: 2 Column: b

Spinning reserve purchases.

Schedule Page: 326.1 Line No.: 2 Column: l

Spinning reserve purchases.

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

Renewable Purchase Power Agreement between Hatch Solar Energy Center 1, LLC (affiliated with NextEra Energy Resource) and El Paso Electric Company effective August 31, 2010, and continues for twenty-five years following the date of commercial operation.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

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

Prior year adjustment.

Schedule Page: 326.1 Line No.: 14 Column: b

Solar Energy Purchase Power Agreement between NRG Solar Roadrunner LLC and El Paso Electric Company dated June 4, 2010, and continues for twenty years following the date of commercial operation.

Schedule Page: 326.2 Line No.: 4 Column: b

Prior year adjustment.

Schedule Page: 326.2 Line No.: 6 Column: b

Spinning reserve purchases.

Schedule Page: 326.2 Line No.: 6 Column: l

Spinning reserve purchases.

Schedule Page: 326.2 Line No.: 8 Column: b

Spinning reserve purchases.

Schedule Page: 326.2 Line No.: 8 Column: l

Spinning reserve purchases.

Schedule Page: 326.2 Line No.: 10 Column: b

Energy conversion services agreement between Shell Energy North America (U.S.), L.P and El Paso Electric Company dated May 17, 2010. Contract is effective January 1, 2011 through September 30, 2014.

Schedule Page: 326.2 Line No.: 10 Column: l

Includes startup and energy conversion fees related to the energy conversion services agreement between Shell Energy North America (U.S.), L.P. and El Paso Electric Company. Also includes gas purchased from various vendors by El Paso Electric and delivered to Pyramid Unit 4 for energy conversion.

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

Prior year adjustment.

Schedule Page: 326.2 Line No.: 12 Column: b

Renewable Purchase Power Agreement between Southwest Environmental Center and El Paso Electric Company. Contract has a minimum twenty year term beginning in 2008.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

Schedule Page: 326.3 Line No.: 10 Column: l

SRSG Charge.

Schedule Page: 326.3 Line No.: 12 Column: l

Prior period adjustment of $(102) and an SRSG charge of $2,470.

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

SRSG Charge.

Schedule Page: 326.4 Line No.: 2 Column: l

SRSG Charge.

Schedule Page: 326.4 Line No.: 6 Column: k

There are no monetary charges associated to this transaction. Transaction settles in-kind exchange of energy.

Schedule Page: 326.5 Line No.: 2 Column: b

Prior year adjustment.

Schedule Page: 326.5 Line No.: 4 Column: c

New Mexico Rate No. 16

Schedule Page: 326.5 Line No.: 4 Column: l

Represents amount paid to various New Mexico customers for excess renewable energy generated by customers and bought by the Company.

Schedule Page: 326.5 Line No.: 5 Column: c

New Mexico Rate No. 33

Schedule Page: 326.5 Line No.: 5 Column: l

Represents amount paid for renewable energy certificates related to renewable energy generated by various New Mexico customers.

Schedule Page: 326.5 Line No.: 6 Column: c

Texas Rate No. 48

Schedule Page: 326.5 Line No.: 6 Column: l

Represents amount paid to various Texas customers for excess renewable energy generated by customers and bought by the Compnay.

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 Classifi-cation (d)
1	El Paso Electric Marketing	Southwestern Public Service Co.	El Paso Electric Marketing	NF
2	El Paso Electric Marketing	Southwestern Public Service Co.	Comision Federal de Electricidad	NF
3	El Paso Electric Marketing	Southwestern Public Service Co.	Comision Federal de Electricidad	SFP
4	El Paso Electric Marketing	El Paso Electric Marketing	Southwestern Public Service Co.	NF
5	El Paso Electric Marketing	El Paso Electric Marketing	Southwestern Public Service Co.	SFP
6	El Paso Electric Marketing	El Paso Electric Marketing	Comision Federal de Electricidad	NF
7	El Paso Electric Marketing	El Paso Electric Marketing	Comision Federal de Electricidad	SFP
8	El Paso Electric Marketing	Tucson Electric Pwr Co.	Southwestern Public Service Co.	NF
9	El Paso Electric Marketing	Salt River Project	Arizona Public Service Co.	NF
10	Rio Grande Electric Co-Op	El Paso Electric Marketing	El Paso Electric Marketing	FNO
11	Arizona Electric Pwr Cooperative	Salt River Project	Arizona Public Service Co.	LFP
12	Arizona Electric Pwr Cooperative	Salt River Project	Arizona Public Service Co.	LFP
13	Arizona Electric Pwr Cooperative	Salt River Project	Arizona Public Service Co.	LFP
14	Arizona Electric Pwr Cooperative	Salt River Project	Arizona Public Service Co.	NF
15	Barclays	Salt River Project	Arizona Public Service Co.	NF
16	Barclays	Arizona Public Service Co.	Salt River Project	NF
17	CitiGroup Energy Inc	Salt River Project	Arizona Public Service Co.	NF
18	CitiGroup Energy Inc	Arizona Public Service Co.	Salt River Project	NF
19	Coral Pwr	Salt River Project	Salt River Project	LFP
20	Coral Pwr	Salt River Project	Arizona Public Service Co.	LFP
21	Coral Pwr	Salt River Project	Arizona Public Service Co.	LFP
22	Coral Pwr	Salt River Project	Arizona Public Service Co.	NF
23	Coral Pwr	Arizona Public Service Co.	Salt River Project	NF
24	CP Energy Marketing	Salt River Project	Arizona Public Service Co.	NF
25	Eagle Energy Partners	Salt River Project	Salt River Project	LFP
26	Eagle Energy Partners	Salt River Project	Salt River Project	NF
27	Eagle Energy Partners	Salt River Project	Salt River Project	NF
28	Eagle Energy Partners	Salt River Project	Salt River Project	SFP
29	JP Morgan Ventures	Salt River Project	Arizona Public Service Co.	NF
30	JP Morgan Ventures	Arizona Public Service Co.	Salt River Project	NF
31	Macquarie Cook Pwr	Salt River Project	Arizona Public Service Co.	NF
32	Macquarie Cook Pwr	Public Service Co. of NM	Southwestern Public Service Co.	NF
33	Macquarie Cook Pwr	Arizona Public Service Co.	Salt River Project	NF
34	Morgan Stanley	Salt River Project	Arizona Public Service Co.	NF
	TOTAL			

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	Morgan Stanley	Arizona Public Service Co.	Salt River Project	NF
2	Morgan Stanley	Salt River Project	Arizona Public Service Co.	SFP
3	Panda Gila River	Salt River Project	Salt River Project	LFP
4	Panda Gila River	Salt River Project	Salt River Project	LFP
5	Panda Gila River	Salt River Project	Salt River Project	LFP
6	Panda Gila River	Salt River Project	Salt River Project	NF
7	Panda Gila River	Salt River Project	Arizona Public Service Co.	NF
8	Panda Gila River	Salt River Project	Salt River Project	NF
9	Panda Gila River	Salt River Project	Arizona Public Service Co.	NF
10	Panda Gila River	Arizona Public Service Co.	Salt River Project	NF
11	Panda Gila River	Salt River Project	Salt River Project	SFP
12	Pwrex	Salt River Project	Arizona Public Service Co.	LFP
13	Pwrex	Salt River Project	Arizona Public Service Co.	NF
14	Pwrex	Arizona Public Service Co.	Salt River Project	NF
15	Pwrex	Salt River Project	Arizona Public Service Co.	SFP
16	Pwrex	Arizona Public Service Co.	Salt River Project	SFP
17	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	LFP
18	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	LFP
19	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	LFP
20	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	LFP
21	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	LFP
22	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
23	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
24	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
25	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
26	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
27	Public Service Co. of NM	El Paso Electric Co.	Public Service Co. of NM	NF
28	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
29	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
30	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
31	Public Service Co. of NM	Public Service Co. of NM	El Paso Electric Co.	NF
32	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
33	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
34	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Classifi-cation (d)
1	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	SFP
2	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
3	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	SFP
4	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	SFP
5	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	SFP
6	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
7	Public Service Co. of NM	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
8	Public Service Co. of NM	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	SFP
9	Public Service Co. of NM	Public Service Co. of NM	Public Service Co. of NM	SFP
10	Transalta	Arizona Public Service Co.	Salt River Project	NF
11	Tristate Generating and Transmission Coop	Tucson Electric Pwr Co.	Public Service Co. of NM	LFP
12	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	LFP
13	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	LFP
14	Tucson Electric Pwr	Salt River Project	Salt River Project	NF
15	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
16	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
17	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	NF
18	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	NF
19	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	NF
20	Tucson Electric Pwr	Salt River Project	Arizona Public Service Co.	NF
21	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	NF
22	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	NF
23	Tucson Electric Pwr	Arizona Public Service Co.	Salt River Project	NF
24	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
25	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
26	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
27	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
28	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
29	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
30	Tucson Electric Pwr	Public Service Co. of NM	Tucson Electric Pwr Co.	SFP
31	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	SFP
32	Tucson Electric Pwr	Salt River Project	Arizona Public Service Co.	SFP
33	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	SFP
34	Tucson Electric Pwr	Tucson Electric Pwr Co.	Tucson Electric Pwr Co.	SFP
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Tucson Electric Pwr	Arizona Public Service Co.	Salt River Project	SFP
2	WestConnect	Public Service Co. of NM	Public Service Co. of NM	NF
3	WestConnect	Salt River Project	Arizona Public Service Co.	AD
4	WestConnect	Salt River Project	Salt River Project	NF
5	WestConnect	Salt River Project	Arizona Public Service Co.	NF
6	Western Area Pwr Admin	Public Service Co. of NM	Public Service Co. of NM	LFP
7	Western Area Pwr Admin - DSW	Salt River Project	Arizona Public Service Co.	NF
8				
9				
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29				
30				
31				
32				
33				
34				
	TOTAL			

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.
01	Eddy	EPE System				1
01	Eddy	Juarez, Mexico		11,450	11,450	2
01	Eddy	Juarez, Mexico		1,400	1,400	3
01	EPE System	Eddy				4
01	EPE System	Eddy		690	690	5
01	EPE System	Juarez, Mexico		12,435	12,435	6
01	EPE System	Juarez, Mexico		2,138	2,138	7
01	Greenlee	Eddy		440	440	8
01	Palo Verde	Westwing		368	368	9
01	EPE System	Coyote/Farmer	8	65,314	65,314	10
01	Palo Verde	Westwing	17	4,791	4,791	11
01	Palo Verde	Westwing	35	36,917	36,917	12
01	Palo Verde	Westwing	50	204,250	204,250	13
01	Palo Verde	Westwing		71	71	14
01	Palo Verde	Westwing		1,130	1,130	15
01	Westwing	Palo Verde		10	10	16
01	Palo Verde	Westwing		3,593	3,593	17
01	Westwing	Palo Verde		16	16	18
01	Palo Verde	Kyrene	133	127,719	127,719	19
01	Palo Verde	Westwing	25	131,091	131,091	20
01	Palo Verde	Westwing	100	277,545	277,545	21
01	Palo Verde	Westwing		1,029	1,029	22
01	Westwing	Palo Verde		480	480	23
01	Palo Verde	Westwing				24
01	Jojoba	Palo Verde	200	127,545	127,545	25
01	Jojoba	Palo Verde		12,403	12,403	26
01	Palo Verde	Jojoba				27
01	Jojoba	Palo Verde		30	30	28
01	Palo Verde	Westwing		4,309	4,309	29
01	Westwing	Palo Verde		486	486	30
01	Palo Verde	Westwing		1,310	1,310	31
01	Westmesa	Eddy		125	125	32
01	Westwing	Palo Verde		5,014	5,014	33
01	Palo Verde	Westwing		81,903	81,903	34
			2,332	**4,493,243**	**4,493,243**	

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
01	Westwing	Palo Verde		3,374	3,374	1
01	Palo Verde	Westwing		802	802	2
01	Jojoba	Palo Verde	630	304,065	304,065	3
01	Jojoba	Palo Verde	430	875,577	875,577	4
01	Jojoba	Palo Verde	200			5
01	Jojoba	Palo Verde		137,747	137,747	6
01	Jojoba	Westwing		100	100	7
01	Palo Verde	Jojoba		3	3	8
01	Palo Verde	Westwing		100,257	100,257	9
01	Westwing	Palo Verde		6,987	6,987	10
01	Palo Verde	Jojoba				11
01	Palo Verde	Westwing	32	62,840	62,840	12
01	Palo Verde	Westwing		40,763	40,763	13
01	Westwing	Palo Verde		23,875	23,875	14
01	Palo Verde	Westwing		134	134	15
01	Westwing	Palo Verde		235	235	16
01	Afton	Springerville	94	90,057	90,057	17
01	Afton	Westmesa	30	43,633	43,633	18
01	Afton	Westmesa	111	87,449	87,449	19
01	Luna	Springerville	60	121,520	121,520	20
01	Westmesa	Amrad	25	224,460	224,460	21
01	Afton	Greenlee				22
01	Afton	Hildago		94	94	23
01	Afton	Luna		93	93	24
01	Afton	Springerville		4	4	25
01	Afton	Westmesa		112	112	26
01	Amrad	Amrad		375	375	27
01	Las Cruces	Amrad		100	100	28
01	Luna	Afton		9	9	29
01	Luna	Amrad		105	105	30
01	Luna	EPE System		10	10	31
01	Luna	Springerville		18	18	32
01	Westmesa	Amrad		8	8	33
01	Westmesa	Las Cruces		227	227	34
			2,332	**4,493,243**	**4,493,243**	

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.
01	Afton	Luna		10,374	10,374	1
01	Afton	Springerville		251	251	2
01	Afton	Westmesa		40,131	40,131	3
01	Las Cruces	Amrad		39,489	39,489	4
01	Luna	Afton		3	3	5
01	Luna	Springerville		8,186	8,186	6
01	Luna	Springerville	60	13,795	13,795	7
01	Springerville	Greenlee				8
01	Westmesa	Amrad		42,522	42,522	9
01	Westwing	Palo Verde		25	25	10
80	Springerville	Las Cruces/Orogrande	50	412,088	412,088	11
01	Luna	Greenlee	30	25,767	25,767	12
01	Luna	Springerville	10			13
01	Jojoba	Kyrene		201	201	14
01	Luna	Greenlee		161,299	161,299	15
01	Luna	Greenlee		211	211	16
01	Luna	Springerville		12,576	12,576	17
01	Macho Springs	Greenlee				18
01	Macho Springs	Springerville		1,001	1,001	19
01	Palo Verde	Westwing		177,926	177,926	20
01	Springerville	Greenlee		648	648	21
01	Springerville	Greenlee		52	52	22
01	Westwing	Palo Verde		1,812	1,812	23
01	Luna	Greenlee		265,978	265,978	24
01	Luna	Greenlee		41	41	25
01	Luna	Greenlee		1	1	26
01	Luna	Springerville				27
01	Luna	Springerville		4,940	4,940	28
01	Luna	Springerville				29
01	Luna	Springerville		250	250	30
01	Macho Springs	Springerville		11,143	11,143	31
01	Palo Verde	Westwing		1,098	1,098	32
01	Springerville	Greenlee		3,186	3,186	33
01	Springerville	Greenlee		3	3	34
			2,332	**4,493,243**	**4,493,243**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.
01	Westwing	Palo Verde		86	86	1
01	Afton	Hildago		188	188	2
01	Jojoba	Westwing		-1	-1	3
01	Palo Verde	Jojoba		1,151	1,151	4
01	Palo Verde	Westwing		126	126	5
01	Westmesa	Holloman	2	11,632	11,632	6
01	Palo Verde	Westwing		4,029	4,029	7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
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						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			2,332	**4,493,243**	**4,493,243**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
				2
				3
				4
				5
				6
				7
				8
				9
193,430	124,367		317,797	10
83,352			83,352	11
171,604			171,604	12
245,152			245,152	13
	39		39	14
	1,432		1,432	15
	9		9	16
	2,906		2,906	17
	16		16	18
1,495,320			1,495,320	19
122,576			122,576	20
490,300			490,300	21
	1,055		1,055	22
	1,207		1,207	23
	1		1	24
859,773	4,381		864,154	25
	25,340		25,340	26
	532		532	27
	53		53	28
	3,655		3,655	29
	441		441	30
	1,608		1,608	31
	1,258		1,258	32
	5,119		5,119	33
	86,263		86,263	34
17,288,194	**8,463,644**	**0**	**25,751,838**	

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.
	3,120		3,120	1
	867		867	2
2,657,175	13,879		2,671,054	3
1,817,049	29,000		1,846,049	4
143,334			143,334	5
	229,934		229,934	6
	320		320	7
	4,556		4,556	8
	111,723		111,723	9
	7,439		7,439	10
	5,188		5,188	11
149,138	11,023		160,161	12
	79,757		79,757	13
	25,856		25,856	14
	145		145	15
	191		191	16
2,402,865			2,402,865	17
872,630			872,630	18
1,564,612			1,564,612	19
1,696,869			1,696,869	20
727,276			727,276	21
	17		17	22
	514		514	23
	508		508	24
	23		23	25
	861		861	26
	2,261		2,261	27
	560		560	28
	80		80	29
	1,541		1,541	30
	57		57	31
	179		179	32
	46		46	33
	1,187		1,187	34
17,288,194	**8,463,644**	**0**	**25,751,838**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.
	81,999		81,999	1
	20,186		20,186	2
	286,879		286,879	3
	266,714		266,714	4
	17		17	5
	884,420		884,420	6
	872,640		872,640	7
	126		126	8
	222,327		222,327	9
	24		24	10
1,386,000			1,386,000	11
145,455			145,455	12
6,100			6,100	13
	490		490	14
	12,916		12,916	15
	1,371		1,371	16
	1,204		1,204	17
	20		20	18
	4,335		4,335	19
	170,731		170,731	20
				21
	166		166	22
	1,976		1,976	23
	9,419		9,419	24
	136		136	25
	6		6	26
	4,781,700		4,781,700	27
	359		359	28
	342		342	29
	926		926	30
	42,385		42,385	31
	966		966	32
				33
				34
17,288,194	**8,463,644**	**0**	**25,751,838**	

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
	918		918	2
	-744		-744	3
	3,577		3,577	4
	287		287	5
58,184			58,184	6
	4,312		4,312	7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
17,288,194	**8,463,644**	**0**	**25,751,838**	

Schedule Page: 328 Line No.: 1 Column: a
El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

Schedule Page: 328 Line No.: 2 Column: a
El Paso Electric Marketing passed on transmission purchases to Comision Federal de Electricidad.

Schedule Page: 328 Line No.: 3 Column: a
El Paso Electric Marketing passed on transmission purchases to Comision Federal de Electricidad.

Schedule Page: 328 Line No.: 4 Column: a
El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

Schedule Page: 328 Line No.: 5 Column: a
El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

Schedule Page: 328 Line No.: 6 Column: a
El Paso Electric Marketing passed on transmission purchases to Comision Federal de Electricidad.

Schedule Page: 328 Line No.: 7 Column: a
El Paso Electric Marketing passed on transmission purchases to Comision Federal de Electricidad.

Schedule Page: 328 Line No.: 8 Column: a
El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

Schedule Page: 328 Line No.: 9 Column: a
El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

Schedule Page: 328 Line No.: 10 Column: d
Network Integration Transmission Service expiration March 31, 2012.

Schedule Page: 328 Line No.: 11 Column: d
Firm transmission contract, expiration January 1, 2021.

Schedule Page: 328 Line No.: 12 Column: d
Firm transmission contract, expiration January 1, 2021.

Schedule Page: 328 Line No.: 13 Column: d
Firm transmission contract, expiration January 1, 2021.

Schedule Page: 328 Line No.: 19 Column: d
Firm transmission contract, expiration January 1, 2014.

Schedule Page: 328 Line No.: 20 Column: d
Firm transmission contract, expiration January 1, 2021.

Schedule Page: 328 Line No.: 21 Column: d
Firm transmission contract, expiration January 1, 2021.

Schedule Page: 328 Line No.: 25 Column: d
Firm transmission contract, expiration October 1, 2013.

Schedule Page: 328.1 Line No.: 3 Column: d
Firm transmission contract, expiration October 1, 2013. Service was partially redirected to daily and hourly services.

Schedule Page: 328.1 Line No.: 4 Column: d
Firm transmission contract, expiration October 1, 2013. Formerly a 630MW yearly contract. PGR partially transferred 200MW of their rights to Eagle Energy Partners (Eagle). PGR remains liable for the 200MW and will be credited both the capacity and dollars in the following month upon El Paso Electric Company's receipt of payment from Eagle. Service was partially redirected to hourly services.

Schedule Page: 328.1 Line No.: 5 Column: d
PGR liability related to their partial transmission assignment to Eagle Energy Partners.

Schedule Page: 328.1 Line No.: 12 Column: d
Firm transmission contract, expiration January 1, 2014. Service was partially redirected to daily and hourly contracts.

Schedule Page: 328.1 Line No.: 17 Column: d
Firm transmission contract, expiration August 1, 2014. Service was partially redirected to daily and hourly contracts.

Schedule Page: 328.1 Line No.: 18 Column: d

Firm transmission contract, expiration January 1, 2014. Service was partially redirected to daily and hourly contracts.

Schedule Page: 328.1 Line No.: 19 Column: d

Firm transmission contract, expiration January 1, 2014. Service was partially redirected to monthly, daily and hourly contracts.

Schedule Page: 328.1 Line No.: 20 Column: d

Firm transmission contract, expiration January 1, 2015. Service was partially redirected to daily contracts.

Schedule Page: 328.1 Line No.: 21 Column: d

Firm transmission contract, expiration July 1, 2013.

Schedule Page: 328.2 Line No.: 11 Column: d

Firm transmission contract, expiration January 1, 2026.

Schedule Page: 328.2 Line No.: 12 Column: d

Firm transmission contract, expiration November 1, 2029.

Schedule Page: 328.2 Line No.: 13 Column: d

Firm transmission contract, expiration November 1, 2029. Service was partially redirected to daily and hourly contracts.

Schedule Page: 328.2 Line No.: 15 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 15 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 17 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 17 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 21 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation.

Schedule Page: 328.2 Line No.: 21 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation.

Schedule Page: 328.2 Line No.: 24 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 24 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 25 Column: l

Service provided from Luna substation where TEP exceeded its contractual 170MWh limit - Post FERC approved settlement.

Schedule Page: 328.2 Line No.: 27 Column: l

To record the transmission revenue receivable resulting from FERC approved settlement with TEP involving disputed transmission service provided from Luna Substation for the period February 2006 through October 2011.

Schedule Page: 328.2 Line No.: 28 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 28 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation. Dollars are for charges where TEP exceeded their 200 MWh limit in place at the time.

Schedule Page: 328.2 Line No.: 29 Column: l

Service provided from Luna substation where TEP exceeded its contractual 170MWh limit - Post FERC approved settlement.

Schedule Page: 328.2 Line No.: 33 Column: i

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation.

Schedule Page: 328.2 Line No.: 33 Column: j

Prior to the FERC approved settlement with TEP reached in November 2011, these MWhs reflect actual transmission service provided from Luna substation.

Schedule Page: 328.3 Line No.: 2 Column: a

Transaction for WestConnect Experimental Point-to-Point Regional Transmission Service.

Schedule Page: 328.3 Line No.: 3 Column: a

Transaction for WestConnect Experimental Point-to-Point Regional Transmission Service Prior Period Adjustment.

Schedule Page: 328.3 Line No.: 4 Column: a

Transaction for WestConnect Experimental Point-to-Point Regional Transmission Service.

Schedule Page: 328.3 Line No.: 5 Column: a

Transaction for WestConnect Experimental Point-to-Point Regional Transmission Service.

Schedule Page: 328.3 Line No.: 6 Column: d

Firm transmission contract, expiration October 1, 2024.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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					
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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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	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	Arizona Public Service	SFP	2,335	2,335		11,520		11,520
2	Arizona Public Service	NF	4,441	4,441		15,252		15,252
3	Public Serv. Co. of NM	OLF	34,216	34,216	607,623			607,623
4	Public Serv. Co. of NM	LFP	643,752	643,752	3,280,122			3,280,122
5	Public Serv. Co. of NM	SFP	113,430	113,430	457,273	299,285		756,558
6	Public Serv. Co. of NM	NF	41,818	41,818		281,040		281,040
7	Salt River Project	OLF	203,831	203,831	1,509,750			1,509,750
8	Salt River Project	SFP	2,389	2,389		8,624		8,624
9	Tristate G&T Assoc, Inc	NF	1,120	1,120		3,845		3,845
10	Tucson Electric Power	OLF	348,550	348,550				
11	Tucson Electric Power	NF	13,267	13,267		89,171		89,171
12	Tucson Electric Power	SFP	1,901	1,901		14,020		14,020
13	Western Area Power Admn	NF	3	3		28		28
14								
15								
16								
	TOTAL		1,411,053	1,411,053	5,854,768	722,785		6,577,553

Schedule Page: 332 Line No.: 1 Column: c
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 1 Column: d
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 1 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 2 Column: c
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 2 Column: d
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 2 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 3 Column: b
Contract is an evergreen contract.

Schedule Page: 332 Line No.: 3 Column: c
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 3 Column: d
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 4 Column: b
Contract expires June 30, 2017.

Schedule Page: 332 Line No.: 4 Column: c
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 4 Column: d
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 5 Column: c
Amounts shown based on actual energy flows and transmission reservations.

Schedule Page: 332 Line No.: 5 Column: d
Amounts shown based on actual energy flows and transmission reservations.

Schedule Page: 332 Line No.: 5 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 6 Column: c
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 6 Column: d
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 6 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 7 Column: b
Contract expires concurrent with the ANPP Participation Agreement.

Schedule Page: 332 Line No.: 7 Column: c
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 7 Column: d
Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 8 Column: c
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 8 Column: d
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 8 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 9 Column: c
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 9 Column: d
Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 9 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 10 Column: b

Service Schedule C terminates on the date of retirement of the last generating unit at Palo Verde Nuclear Generating Station, subject to twelve-month notice of termination by the Company.

Schedule Page: 332 Line No.: 10 Column: c

Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 10 Column: d

Amounts shown based on actual energy flows.

Schedule Page: 332 Line No.: 10 Column: e

Under a pre-order 888/889 agreement, the Company was assigned rights as part of the Power Exchange and Transmission Agreement.

Schedule Page: 332 Line No.: 11 Column: c

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 11 Column: d

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 11 Column: f

Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 12 Column: c

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 12 Column: d

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 12 Column: f

Amounts shown include short term transmission reservations, related ancillary and losses.

Schedule Page: 332 Line No.: 13 Column: c

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 13 Column: d

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 13 Column: f

Amounts shown include short term transmission reservations, related ancillary and losses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	369,914
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	825,996
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	7,190
6	Palo Verde General Expenses	10,137,357
7	Director's Fees and Expenses	2,281,232
8	Four Corners General Expenses	647,892
9	Palo Verde Trans Line Costs	47,183
10	Travel	128,345
11	Mesilla Valley Economic Development Alliance	25,000
12	El Paso Regional Economic Development Fund	250,000
13	UTEP Renewable Energy Program reclassed to Donations	-200,000
14		
15		
16		
17		
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22		
23		
24		
25		
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41		
42		
43		
44		
45		
46	TOTAL	14,520,109

Schedule Page: 335 Line No.: 5 Column: b

Consists primarily of $6,524 for expenses related to Human Resources functions including new employee orientation

Schedule Page: 335 Line No.: 13 Column: b

Represents the reclassification of an amount expensed in a prior period to FERC account 426.1, Donations.

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			6,668,400		6,668,400
2	Steam Production Plant	18,400,914	-22,452			18,378,462
3	Nuclear Production Plant	18,745,963	-1,056,754			17,689,209
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	720,546	416			720,962
7	Transmission Plant	6,444,390				6,444,390
8	Distribution Plant	18,512,488				18,512,488
9	Regional Transmission and Market Operation					
10	General Plant	8,523,691				8,523,691
11	Common Plant-Electric					
12	TOTAL	71,347,992	-1,078,790	6,668,400		76,937,602

B. Basis for Amortization Charges

Asset	Term	Basis	Amort Exp	Method
Computer Software	5 - 10 years	$63,417,494	$6,668,400	Straight Line

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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	Nuclear Prod Plant						
13	Palo Verde Nuclear St						
14							
15	Unit 1	439,516	60.00				34.00
16	Unit 2	547,127	60.00				35.00
17	Unit 3	495,005	60.00				36.00
18	Common	153,459	60.00				36.00
19	Water Rec Fac	117,216	60.00				36.00
20	Sub-total Nuclear Prod	1,752,323					
21							
22							
23							
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Schedule Page: 336 Line No.: 15 Column: c

The NRC granted Palo Verde a 20 year license extension in April 2011.

Schedule Page: 336 Line No.: 15 Column: e

Since 2001, all capital additions to Palo Verde are depreciated over the remaining life of each unit from each year of the plant addition.

Schedule Page: 336 Line No.: 16 Column: c

The NRC granted Palo Verde a 20 year license extension in April 2011.

Schedule Page: 336 Line No.: 16 Column: e

Since 2001, all capital additions to Palo Verde are depreciated over the remaining license life of each unit from each year of the plant addition.

Schedule Page: 336 Line No.: 17 Column: c

The NRC granted Palo Verde a 20 year license extension in April 2011.

Schedule Page: 336 Line No.: 17 Column: e

Since 2001, all capital additions to Palo Verde are depreciated over the remaining license life of each unit from each year of the plant addition.

Schedule Page: 336 Line No.: 18 Column: c

The NRC granted Palo Verde a 20 year license extension in April 2011.

Schedule Page: 336 Line No.: 18 Column: e

Since 2001, all capital additions to Palo Verde are depreciated over the remaining license life of each unit from each year of the plant addition.

Schedule Page: 336 Line No.: 19 Column: c

The NRC granted Palo Verde a 20 year license extension in April 2011.

Schedule Page: 336 Line No.: 19 Column: e

Since 2001, all capital additions to Palo Verde are depreciated over the remaining license life of each unit from each year of the plant addition.

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	Year/Period of Report 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				
2	FERC General and Other		371,875	371,875	
3	FERC Annual Fee		650,617	650,617	
4					
5	Public Utility Commission of Texas				
6	Texas 2009 Rate Case Costs		2,284,080	2,284,080	3,298,067
7	Texas General and Other		184,419	184,419	
8	Texas 2012 Rate Case Costs				
9					
10	New Mexico Public Regulation Commission				
11	New Mexico 2009 Rate Case Costs		252,648	252,648	505,511
12	2010 FPPCAC Audit		683	683	1,127
13	New Mexico Procurement Plan		99,544	99,544	
14	New Mexico Energy Efficiency Filings		122,142	122,142	
15	New Mexico General and Other		1,015	1,015	
16					
17	Nuclear Regulatory Commission				
18	PVNGS Unit 1 Fees		901,749	901,749	
19	PVNGS Unit 2 Fees		906,405	906,405	
20	PVNGS Unit 3 Fees		883,507	883,507	
21					
22	Other		59,906	59,906	
23					
24					
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26					
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45					
46	TOTAL		6,718,590	6,718,590	3,804,705

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.
							1
	928	371,875					2
	928	650,617					3
							4
							5
	928	2,284,080	128,440	182.3	-2,280,921	1,145,586	6
	928	184,419					7
			648,431			648,431	8
							9
							10
	928	252,648		182.3	-252,648	252,863	11
	928	683	426,143	182.3		427,270	12
	928	99,544					13
	928	122,142					14
	928	1,015					15
							16
							17
	928	901,749					18
	928	906,405					19
	928	883,507					20
							21
	928	59,906					22
							23
							24
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		6,718,590	1,203,014		-2,533,569	2,474,150	46

FOOTNOTE DATA

Schedule Page: 350 Line No.: 6 Column: a

Represents Texas rate case costs related to Docket No. 37690 which the Company filed with the PUCT in December 2009. These costs are being amortized over two years beginning in July 2010.

Schedule Page: 350 Line No.: 8 Column: a

Represents Texas rate case costs related to Docket No. 40094 which the Company filed with the PUCT in February 2012.

Schedule Page: 350 Line No.: 11 Column: a

Represents New Mexico rate case costs approved in Case No. 09-00171 UT which the Company filed with the NMPRC in May 2009. These costs are being amortized over a three year period beginning in January 2010.

Schedule Page: 350 Line No.: 12 Column: a

Represents New Mexico Fuel and Purchased Power Cost Adjustment Clause ("FPPCAC") audit costs in Case No. 10-00065 UT.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	7,117,112		
4	Transmission	4,932,793		
5	Regional Market			
6	Distribution	8,127,388		
7	Customer Accounts	8,969,249		
8	Customer Service and Informational			
9	Sales			
10	Administrative and General	24,546,355		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	53,692,897		
12	Maintenance			
13	Production	5,011,063		
14	Transmission	584,364		
15	Regional Market			
16	Distribution	2,448,038		
17	Administrative and General	260,612		
18	TOTAL Maintenance (Total of lines 13 thru 17)	8,304,077		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	12,128,175		
21	Transmission (Enter Total of lines 4 and 14)	5,517,157		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	10,575,426		
24	Customer Accounts (Transcribe from line 7)	8,969,249		
25	Customer Service and Informational (Transcribe from line 8)			
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	24,806,967		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	61,996,974	546,282	62,543,256
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	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)	61,996,974	546,282	62,543,256
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	15,483,260	1,184,833	16,668,093
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	15,483,260	1,184,833	16,668,093
72	Plant Removal (By Utility Departments)			
73	Electric Plant	347		347
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	347		347
77	Other Accounts (Specify, provide details in footnote):			
78	In-Kind Donations and Exp for Certain Civic, Political & Rel	145,834	414	146,248
79	Other			
80				
81				
82				
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87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	145,834	414	146,248
96	TOTAL SALARIES AND WAGES	77,626,415	1,731,529	79,357,944

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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.

None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)				
7					
8					
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46	TOTAL				

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	8,342,116	MWh	800,843	3,581,796	MWh	1,198,811
2	Reactive Supply and Voltage	8,342,116	MWh	500,527	822,021	MWh	225,687
3	Regulation and Frequency Response				62,664	MWh	2,613
4	Energy Imbalance						
5	Operating Reserve - Spinning				62,664	MWh	10,510
6	Operating Reserve - Supplement				62,664	MWh	10,510
7	Other						
8	Total (Lines 1 thru 7)	16,684,232		1,301,370	4,591,809		1,448,131

Schedule Page: 398 Line No.: 1 Column: b

Ancillary Services Purchased represents service to Native Load that El Paso Electric Company self-provides from its own facilities. The dollar values are imputed as though El Paso Electric Company took these services under its own tariff.

Schedule Page: 398 Line No.: 1 Column: d

Ancillary Services Purchased represents service to Native Load that El Paso Electric Company self-provides from its own facilities. The dollar values are imputed as though El Paso Electric Company took these services under its own tariff.

Schedule Page: 398 Line No.: 1 Column: e

The Number of Units includes 437,501 MWh from hourly services, (of which 16,351 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 317,593 MWh from daily services; 22,315 MWh from weekly services; 13,235 MWh from monthly services; and 2,791,152 MWh from yearly contracts, (of which 62,664 MWh were sold to Rio Grande Electric Co-Op, a network customer of El Paso Electric Company).

Schedule Page: 398 Line No.: 1 Column: g

$56,396 pertains to hourly services (of which $5,935 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $63,531 pertains to daily services (of which $403 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $9,720 pertains to weekly services; $25,200 pertains to monthly services and $1,043,964 pertains to yearly contracts, (of which $6,805 pertains to Rio Grande Electric Co-Op, a network customer of El Paso Electric Company).

Schedule Page: 398 Line No.: 2 Column: b

Ancillary Services Purchased represents service to Native Load that El Paso Electric Company self-provides from its own facilities. The dollar values are imputed as though El Paso Electric Company took these services under its own tariff.

Schedule Page: 398 Line No.: 2 Column: d

Ancillary Services Purchased represents service to Native Load that El Paso Electric Company self-provides from its own facilities. The dollar values are imputed as though El Paso Electric Company took these services under its own tariff.

Schedule Page: 398 Line No.: 2 Column: e

The Number of Units includes 78,668 MWh from hourly services (of which 15,983 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 87,465 MWh from daily services; 13,235 MWh from monthly services; and 642,653 MWh from yearly contracts, (of which 62,664 MWh were sold to Rio Grande Electric Co-Op, a network customer of El Paso Electric Company).

Schedule Page: 398 Line No.: 2 Column: g

$9,834 pertains to hourly services (of which $3,687 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $22,215 pertains to daily services (of which $254 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $15,840 pertains to monthly services and $177,798 pertains to yearly contracts, (of which $4,262 pertains to Rio Grande Electric Co-Op, a network customer of El Paso Electric Company).

Schedule Page: 398 Line No.: 3 Column: e

All units pertain to yearly contract with Rio Grande Electric Co-Op, a network customer of El Paso Electric Company.

Schedule Page: 398 Line No.: 3 Column: g

All from yearly contract with Rio Grande Electric Co-Op, a network customer of El Paso Electric Company.

Schedule Page: 398 Line No.: 5 Column: e

All units pertain to yearly contract with Rio Grande Electric Co-Op, a network customer of El Paso Electric Company.

Schedule Page: 398 Line No.: 5 Column: g

All from yearly contract with Rio Grande Electric Co-Op, a network customer of El Paso Electric Company.

Schedule Page: 398 Line No.: 6 Column: e

All units pertain to yearly contract with Rio Grande Electric Co-Op, a network customer of

El Paso Electric Company.

Schedule Page: 398 Line No.: 6 Column: g

All from yearly contract with Rio Grande Electric Co-Op, a network customer of El Paso Electric Company.

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	Year/Period of Report 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	1,064	12	2000		5	1,281	50	63	
2	February	1,171	1	2000		2	1,262	50	82	
3	March	1,014	31	2000		9	1,281	50	63	
4	Total for Quarter 1	3,249				16	3,824	150	208	
5	April	1,176	20	1600		8	1,282	50	62	
6	May	1,384	31	1600		10	1,276	50	68	
7	June	1,679	27	1500		11	1,257	50	87	
8	Total for Quarter 2	4,239				29	3,815	150	217	
9	July	1,632	20	1500		11	1,471	50	73	
10	August	1,714	8	1600		12	1,271	50	73	
11	September	1,597	1	1600		11	1,273	50	71	
12	Total for Quarter 3	4,943				34	4,015	150	217	
13	October	1,225	4	1500		8	1,282	50	62	
14	November	1,024	28	1900		4	1,251	50	133	
15	December	1,213	5	2000		6	1,239	50	145	
16	Total for Quarter 4	3,462				18	3,772	150	340	
17	Total Year to Date/Year	15,893				97	15,426	600	982	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	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)	7,661,213
3	Steam	3,953,594	23	Requirements Sales for Resale (See instruction 4, page 311.)	62,656
4	Nuclear	4,942,055	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,296,319
5	Hydro-Conventional		25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	11,204
7	Other	41,127	27	Total Energy Losses	626,668
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	11,658,060
9	Net Generation (Enter Total of lines 3 through 8)	8,936,776			
10	Purchases	2,711,491			
11	Power Exchanges:				
12	Received	53,883			
13	Delivered	44,090			
14	Net Exchanges (Line 12 minus line 13)	9,793			
15	Transmission For Other (Wheeling)				
16	Received	4,493,243			
17	Delivered	4,493,243			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	11,658,060			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report 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	928,031	311,886	1,064	12	2000
30	February	901,083	352,307	1,171	1	2000
31	March	994,130	250,631	1,014	31	2000
32	April	793,941	318,046	1,176	20	1600
33	May	935,348	238,158	1,384	31	1600
34	June	1,118,453	277,408	1,679	27	1500
35	July	1,236,840	342,021	1,632	20	1500
36	August	1,175,247	249,199	1,714	8	1600
37	September	1,050,512	294,641	1,597	1	1600
38	October	830,264	187,496	1,225	4	1500
39	November	743,428	170,804	1,024	28	1900
40	December	950,783	303,722	1,213	5	2000
41	TOTAL	11,658,060	3,296,319			

Schedule Page: 401 Line No.: 10 Column: b
Includes 608,688 MWhs related to purchases to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 20 Column: b
Includes 608,688 MWhs related to purchases to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 24 Column: b
Includes 608,688 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 28 Column: b
Includes 608,688 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 29 Column: b
Includes 53,144 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 29 Column: c
Includes 53,144 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 30 Column: b
Includes 46,140 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 30 Column: c
Includes 46,140 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 31 Column: b
Includes 47,920 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 31 Column: c
Includes 47,920 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 32 Column: b
Includes 54,959 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 32 Column: c
Includes 54,959 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 33 Column: b
Includes 57,388 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 33 Column: c
Includes 57,388 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 34 Column: b
Includes 52,845 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 34 Column: c
Includes 52,845 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 35 Column: b
Includes 54,333 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 35 Column: c
Includes 54,333 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 36 Column: b

Includes 52,975 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 36 Column: c

Includes 52,975 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 37 Column: b

Includes 51,800 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 37 Column: c

Includes 51,800 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 38 Column: b

Includes 48,279 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 38 Column: c

Includes 48,279 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 39 Column: b

Includes 40,040 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 39 Column: c

Includes 40,040 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 40 Column: b

Includes 48,865 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Schedule Page: 401 Line No.: 40 Column: c

Includes 48,865 MWhs related to sales to Freeport-McMoRan related to the Company's Power Purchase and Sales Agreement with Freeport-McMoRan dated December 16, 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Rio Grande* (b)			Plant Name: *Newman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Indoor and Outdoor			Indoor and Outdoor		
3	Year Originally Constructed	1929			1959		
4	Year Last Unit was Installed	1972			2011		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	266.00			889.00		
6	Net Peak Demand on Plant - MW (60 minutes)	236			682		
7	Plant Hours Connected to Load	8496			8717		
8	Net Continuous Plant Capability (Megawatts)	229			752		
9	When Not Limited by Condenser Water	238			761		
10	When Limited by Condenser Water	229			752		
11	Average Number of Employees	51			74		
12	Net Generation, Exclusive of Plant Use - KWh	700160000			2605502000		
13	Cost of Plant: Land and Land Rights	100946			181900		
14	Structures and Improvements	4696721			21162728		
15	Equipment Costs	51829842			375162112		
16	Asset Retirement Costs	76983			-325470		
17	Total Cost	56704492			396181270		
18	Cost per KW of Installed Capacity (line 17/5) Including	213.1748			445.6482		
19	Production Expenses: Oper, Supv, & Engr	642053			1446141		
20	Fuel	39289725			121960133		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1616958			1098615		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	179407			2182344		
26	Misc Steam (or Nuclear) Power Expenses	1521490			2631715		
27	Rents	631			515339		
28	Allowances	0			142023		
29	Maintenance Supervision and Engineering	629587			870460		
30	Maintenance of Structures	429692			609416		
31	Maintenance of Boiler (or reactor) Plant	3660599			5058576		
32	Maintenance of Electric Plant	2333217			5858967		
33	Maintenance of Misc Steam (or Nuclear) Plant	410051			889069		
34	Total Production Expenses	50713410			143262798		
35	Expenses per Net KWh	0.0724			0.0550		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf			Mcf	BBL	
38	Quantity (Units) of Fuel Burned	8067884	0	0	25255752	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1024000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.870	0.000	0.000	4.829	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.870	0.000	0.000	4.829	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.756	0.000	0.000	4.734	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.056	0.000	0.000	0.047	0.000	0.000
44	Average BTU per KWh Net Generation	11799.000	0.000	0.000	9887.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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: *Four Corners* (d)			Plant Name: *Copper* (e)			Plant Name: *Palo Verde* (f)			Line No.
					Gas Turbine				1
					Outdoor				2
					1979				3
					1980				4
		0.00			79.00			0.00	5
		0			63			0	6
		0			1115			0	7
		0			62			0	8
		0			62			0	9
		0			62			0	10
		0			12			0	11
		647932000			38997000			4942055000	12
		8623			10000			2347703	13
		2991985			731436			462854759	14
		85761028			14358580			1220714402	15
		31491			15479			-40328558	16
		88793127			15115495			1645588306	17
		0			191.3354			0	18
		245636			0			12884201	19
		11766040			3053028			44118186	20
		0			0			5890634	21
		1346419			0			5741310	22
		0			0			0	23
		0			0			0	24
		103771			0			3666805	25
		563552			101535			19511705	26
		906542			0			87698	27
		0			0			0	28
		201846			1151			4998318	29
		94052			23508			1657811	30
		1715122			183296			7454367	31
		510224			-56926			8401683	32
		817044			0			2737833	33
		18270248			3305592			117150551	34
		0.0282			0.0848			0.0237	35
Coal	Gas		Gas			Nuclear			36
Ton	Mcf		Mcf			MMbtu			37
365390	23055	0	675052	0	0	50896015	0	0	38
17604981	1010000	0	1019000	0	0	0	0	0	39
31.792	6.488	0.000	4.523	0.000	0.000	0.867	0.000	0.000	40
31.792	6.488	0.000	4.523	0.000	0.000	0.867	0.000	0.000	41
1.806	6.424	0.000	4.438	0.000	0.000	0.867	0.000	0.000	42
0.018	0.000	0.000	0.078	0.000	0.000	0.009	0.000	0.000	43
9964.000	0.000	0.000	17639.000	0.000	0.000	10299.000	0.000	0.000	44

Schedule Page: 402 Line No.: 1 Column: d

Jointly owned plant.

Schedule Page: 402 Line No.: 1 Column: f

Jointly owned plant.

Schedule Page: 402 Line No.: 2 Column: d

Data on lines 2-11 for total plant to be reported by the Operating Agent, Arizona Public Service Company.

Schedule Page: 402 Line No.: 2 Column: f

Data on lines 2-11 for total plant to be reported by the Operating Agent, Arizona Public Service Company.

Schedule Page: 402 Line No.: 20 Column: b

Excludes penalty and revenue sharing credits of $16,507 related to contract with El Paso Natural Gas.

Schedule Page: 402 Line No.: 20 Column: c

Excludes penalty and revenue sharing credits of $26,200 related to contract with El Paso Natural Gas.

Schedule Page: 402 Line No.: 20 Column: d

Excludes $3,507,132 related to the amortization of final coal reclamation costs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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
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			8
			9
			10
			11
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			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	End of 2011/Q4

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						
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7						
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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
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						13
						14
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						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Palo Verde	Kyrene	500.00	500.00	(1),(3)		75.00	1
2	Palo Verde	Westwing	500.00	500.00	(3)		45.00	2
3								
4	Newman	West Mesa	345.00	345.00	(2)	232.20		1
5	Newman	Afton	345.00	345.00	(2)	29.88		1
6	Afton	Luna	345.00	345.00	(2)	57.26		1
7	Luna	Greenlee	345.00	345.00	(2)		109.80	1
8	Newman	Eddy County	345.00	345.00	(2)	78.80	125.40	1
9	Diablo	Luna	345.00	345.00	(2)	84.90		1
10	Luna	Macho Springs	345.00	345.00	(2),(3)	24.86		1
11	Macho Springs	Springerville	345.00	345.00	(2),(3)	201.38		1
12								
13								
14	Various 115kV Lines		115.00	115.00	(1),(2)	435.57	49.37	1
15	Various 69kV Lines		69.00	69.00	(1),(2)	200.32	25.80	1
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,345.17	430.37	13

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1780 ACSR	1,560,377	7,027,603	8,587,980					1
1780 ACSR	1,203,340	5,419,588	6,622,928					2
								3
795 ACSR	930,038	11,732,414	12,662,452					4
795 ACSR	423,552	4,122,103	4,545,655					5
795 ACSR	811,653	7,899,195	8,710,848					6
795 ACSR	86,513	1,414,579	1,501,092					7
954 ACSR/T2	3,107,408	17,242,074	20,349,482					8
954 ACSR	1,114,625	12,378,266	13,492,891					9
954 ACSR	173,895	60,781,234	60,955,129					10
954 ACSR								11
								12
								13
Various	1,986,338	44,246,700	46,233,038					14
Various	309,717	10,531,181	10,840,898					15
								16
								17
								18
								19
								20
								21
								22
								23
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								28
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								31
								32
								33
								34
								35
	11,707,456	182,794,937	194,502,393					36

Schedule Page: 422 Line No.: 1 Column: g

EPE Ownership - 18.7%

Schedule Page: 422 Line No.: 2 Column: g

EPE Ownership - 18.7%

Schedule Page: 422 Line No.: 4 Column: b

Includes intermediate station - Arroyo.

Schedule Page: 422 Line No.: 7 Column: b

Includes intermediate station - Hidalgo.

Schedule Page: 422 Line No.: 7 Column: g

EPE Ownership - 57.2% Luna-Hidalgo (50.0 mi), 40% Hidalgo-Greenlee (59.8 mi).

Schedule Page: 422 Line No.: 8 Column: b

Includes intermediate stations - Caliente Amrad.

Schedule Page: 422 Line No.: 8 Column: f

EPE Ownership - 100% Newman - Caliente (22.8 mi), 100% Caliente - Amrad (56.0 mi).

Schedule Page: 422 Line No.: 8 Column: g

EPE Ownership - 66.7% Amrad-Eddy County (125.4 mi).

Schedule Page: 422 Line No.: 10 Column: f

Composed of (2) H-frame wood or steel poles (146.90 mi) and (3) tower (77.80 mi).

Schedule Page: 422 Line No.: 10 Column: j

Includes total cost from Luna to Macho Springs and from Macho Springs to Springerville.

Schedule Page: 422 Line No.: 10 Column: k

Includes total cost from Luna to Macho Springs and from Macho Springs to Springerville.

Schedule Page: 422 Line No.: 10 Column: l

Includes total cost from Luna to Macho Springs and from Macho Springs to Springerville.

Schedule Page: 422 Line No.: 14 Column: g

Includes double circuit and underbuilt segments of line.

Schedule Page: 422 Line No.: 15 Column: g

Includes double circuit and underbuilt segments of line.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
4							
5							
6							
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8							
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41							
42							
43							
44	TOTAL						

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.
									1
									2
									3
									4
									5
									6
									7
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									9
									10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	10,000 kVA and Over				
2					
3	Afton La Mesa, NM	Trans. UA			
4	Altura El Paso	Dist. UA	13.80	4.16	
5	Americas El Paso	Dist. UA	69.00	13.80	
6	Amrad Oro Grande, NM	Trans. UA	345.00	115.00	13.00
7	Amrad Oro Grande, NM	Dist. UA	115.00	24.90	
8	Anthony Anthony, NM	Dist. UA	115.00	24.90	
9	Apollo New Mexico	Dist. UA	69.00	2.40	
10	Arroyo Las Cruces, NM	Trans. UA	345.00	345.00	
11	Arroyo Las Cruces, NM	Trans. UA	345.00	115.00	13.80
12	Arroyo Las Cruces, NM	Dist. UA	115.00	23.90	
13	Arroyo Las Cruces, NM	Dist. UA	115.00	23.90	
14	Ascarate El Paso	Dist. UA	115.00	69.00	13.80
15	Ascarate El Paso	Dist. UA	115.00	69.00	
16	Ascarate El Paso	Dist. UA	69.00	13.80	
17	Ascarate El Paso	Dist. UA	69.00	4.16	
18	Austin El Paso	Dist. UA	115.00	13.80	
19	Austin El Paso	Dist. UA	69.00	4.16	
20	Biggs El Paso	Dist. UA	115.00		
21	Border Steel El Paso	Dist. UA	115.00	13.80	
22	Butterfield El Paso	Dist. UA	115.00	13.80	
23	Caliente El Paso	Trans. UA	345.00	115.00	13.80
24	Caliente El Paso	Trans. UA	115.00	13.80	
25	Chaparral Chaparral, NM	Dist. UA	115.00	13.80	
26	Clint Lower Valley	Dist. UA	69.00	13.80	
27	Clint Lower Valley	Dist. UA	69.00	4.16	
28	Copper El Paso	Dist. UA	13.80	115.00	
29	Copper El Paso	Dist. UA	115.00	13.80	
30	Copper El Paso	Dist. UA	13.80	45.80	
31	Copper El Paso	Dist. UA	13.80	0.48	
32	Cox New Mexico	Trans. UA	115.00	69.00	
33	Coyote Lower Valley	Dist. UA	115.00	13.80	
34	Cromo El Paso	Dist. UA	115.00	13.80	
35	Dallas El Paso	Dist. UA	69.00	13.80	
36	Dallas El Paso	Dist. UA	69.00	13.80	
37	Dallas El Paso	Dist. UA	13.80	4.16	
38	Diablo Sunland Park, NM	Trans. UA	345.00	115.00	13.80
39	Durazno El Paso	Dist. UA	115.00	13.80	
40	Dyer El Paso	Dist. UA	69.00	13.80	

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	Dyer El Paso	Dist. UA	115.00	69.00	
2	EMRLD New Mexico	Dist. UA	115.00	13.80	
3	Farah El Paso	Dist. UA	69.00	13.80	
4	Felipe El Paso	Dist. UA	69.00	214.90	
5	Fort Bliss El Paso	Dist. UA	115.00	13.80	
6	Global Reach El Paso	Dist. UA	115.00	13.80	
7	Hatch New Mexico	Dist. UA	115.00	24.90	
8	Hatch New Mexico	Dist. UA	23.90	4.16	
9	Lane Lower Valley	Dist. UA	115.00	69.00	
10	Lane Lower Valley	Dist. UA	115.00	13.80	
11	Las Cruces Las Cruces, NM	Dist. UA	115.00	24.00	
12	Las Cruces Las Cruces, NM	Dist. UA	23.90	4.16	
13	Las Cruces Las Cruces, NM	Dist. UA	115.00	23.90	
14	Leo El Paso	Dist. UA	69.00	13.80	
15	Leo El Paso	Dist UA	13.80	4.16	
16	Mann Lower Valley	Dist. UA	69.00	13.80	
17	Mann Lower Valley	Dist. UA	69.00	13.80	
18	Mesa El Paso	Dist. UA	115.00	13.80	
19	Milagro El Paso	Dist. UA	115.00	69.00	
20	Milagro El Paso	Dist. UA	115.00	13.80	
21	Montoya Upper Valley, NM	Dist. UA	115.00	23.90	
22	Montwood El Paso	Dist. UA	115.00	23.90	
23	Newman T-1	Trans. UA	345.00	115.00	13.80
24	Newman T-2	Trans. UA	13.80	115.00	
25	Newman T-3	Dist. UA	115.00	2.40	
26	Newman T-4	Dist. UA	13.80	2.40	
27	Newman T-5	Dist. UA	13.80	2.40	
28	Newman T-6	Trans. UA	13.80	115.00	
29	Newman T-7	Dist. UA	13.80	2.40	
30	Newman T-8	Trans. UA	13.80	115.00	
31	Newman T-9	Trans. UA	13.80	115.00	
32	Newman T-10	Dist. UA	13.80	4.16	
33	Newman T-11	Trans. UA	13.80	115.00	
34	Newman T-12	Dist. UA	115.00	4.16	
35	Newman T-13	Trans. UA	13.80	115.00	
36	Newman T-14	Trans. UA	13.80	115.00	
37	Newman T-15	Trans. UA	13.80	115.00	
38	Newman T-16	Trans. UA	13.80	115.00	
39	Newman T-17	Dist. UA	13.80	4.16	
40	Newman T-18	Dist. UA	13.80	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Picante T-1	Trans. UA	345.00	115.00	
2	Santa Teresa T-2	Trans. UA	115.00	24.90	
3	Phelps Dodge El Paso	Dist. UA	69.00	13.80	
4	Phelps Dodge El Paso	Dist. UA	13.80	2.30	
5	Phelps Dodge El Paso	Dist. UA	13.80	4.16	
6	Pellicano El Paso	Dist. UA	115.00	23.90	
7	Picacho New Mexico	Dist. UA	115.00	23.90	
8	Redeye New Mexico	Dist. UA	115.00	13.80	
9	Rio Grande Sunland Park, New Mexico	Dist. UA	17.20	115.00	
10	Rio Grande Sunland Park, New Mexico	Dist. UA	115.00	69.00	
11	Rio Grande Sunland Park, New Mexico	Dist. UA	69.00	2.40	
12	Rio Grande Sunland Park, New Mexico	Dist. UA	13.80	4.16	
13	Rio Grande Sunland Park, New Mexico	Trans. UA	18.00	4.16	
14	Rio Grande Sunland Park, New Mexico	Trans. UA	13.80	69.00	
15	Rio Grande Sunland Park, New Mexico	Trans. UA	14.40	4.16	
16	Rio Grande Sunland Park, New Mexico	Dist. UA	69.00	14.40	
17	Rio Grande Sunland Park, New Mexico	Trans. UA	13.80	2.40	
18	Rio Grande Sunland Park, New Mexico	Dist. UA	13.80	2.30	
19	Rio Grande Sunland Park, New Mexico	Dist. UA	14.40	2.40	
20	Ripley El Paso	Dist. UA	115.00	13.80	
21	Pendale Temp El Paso	Dist. UA	115.00	13.80	
22	Salopek Las Cruces, NM	Dist. UA	115.00	24.90	
23	Santa Fe El Paso	Dist. UA	69.00	13.80	
24	Santa Fe El Paso	Dist. UA	13.80	4.16	
25	Santa Teresa Santa Teresa	Dist. UA	115.00	24.90	
26	Scotsdale El Paso	Dist. UA	115.00	69.00	
27	Scotsdale El Paso	Dist. UA	115.00	13.80	
28	Shearman El Paso	Dist. UA	115.00	13.80	
29	Socorro Lower Valley	Dist. UA	69.00	13.80	
30	Sol El Paso	Dist. UA	115.00	13.80	
31	Sparks El Paso	Dist. UA	115.00	13.80	
32	Sunset El Paso	Dist. UA	69.00	13.80	
33	Sunset El Paso	Dist. UA	69.00	4.16	
34	Sunset North El Paso	Dist. UA	115.00	13.80	
35	Thorn El Paso	Dist. UA	115.00	13.80	
36	Viscount El Paso	Dist. UA	69.00	13.80	
37	Vista El Paso	Dist. UA	115.00	13.80	
38	White Sands New Mexico	Dist. UA	115.00	13.80	
39	Wrangler El Paso	Dist. UA	115.00	13.80	
40	Wrangler El Paso	Dist. UA	115.00	69.00	

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	Rio Bosque	Dist. UA	115.00	13.80	
2	Leo Temp	Dist. UA	69.00	13.80	
3	5,000 to 10,000 kVA				
4					
5	Alamo Lower Valley	Dist. UA	69.00	24.00	
6	Clint Lower Valley	Dist. UA	69.00	13.80	
7	Clint Lower Valley	Dist. UA	69.00	4.16	
8	Darbyshire El Paso	Dist. UA	69.00	13.80	
9	Diana El Paso	Dist. UA	13.80	4.16	
10	Farmer Van Horn	Dist. UA	69.00	23.90	
11	Five Points El Paso	Dist. UA	13.80	4.16	
12	Horizon Horizon	Dist. UA	69.00	13.80	
13	Locust New Mexico	Dist. UA	23.90	4.16	
14	Mar New Mexico	Dist. UA	115.00	4.16	
15	Mar New Mexico	Dist. UA	24.90	4.16	
16	McGregor New Mexico	Dist. UA	69.00	13.80	
17	Proler Proler	Dist. UA	69.00	2.40	
18	S.P. Pipeline El Paso	Dist. UA	13.80	2.40	
19	Sierra Blanca Sierra Blanca	Dist. UA	69.00	24.00	
20	Sierra Blanca Sierra Blanca	Dist. UA	23.90	4.16	
21	Tobin El Paso	Dist. UA	13.80	4.16	
22	Valley Lower Valley	Dist. UA	69.00	13.80	
23	Durazno El Paso	Dist. UA	69.00	13.80	
24	1,000 to 5,000 kVA				
25					
26	Alameda Las Cruces, NM	Dist. UA	23.90	4.16	
27	Beaumont El Paso	Dist. UA	13.80	4.16	
28	Cadwallader El Paso	Dist. UA	13.80	4.16	
29	Canutillo Upper Valley	Dist. UA	23.90	4.16	
30	Cielo El Paso	Dist. UA	13.80	4.16	
31	Cinecue El Paso	Dist. UA	13.80	4.16	
32	Clardy El Paso	Dist. UA	13.80	4.16	
33	Coronado El Paso	Dist. UA	13.80	4.16	
34	Cotton El Paso	Dist. UA	13.80	4.16	
35	East El Paso	Dist. UA	13.80	4.16	
36	Fabens Lower Valley	Dist. UA	69.00	4.16	
37	Franklin El Paso	Dist. UA	13.80	4.16	
38	Fresno El Paso	Dist. UA	13.80	4.16	
39	Frontera Upper Valley	Dist. UA	13.80	4.16	
40	Grace El Paso	Dist. UA	13.80	4.16	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	04/09/2012	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	Griggs Upper Valley	Dist. UA	23.90	4.16	
2	Hacienda El Paso	Dist. UA	13.80	4.16	
3	Hanes New Mexico	Dist. UA	23.90	4.16	
4	Hueco El Paso	Dist. UA	69.00	23.90	
5	Hueco El Paso	Dist. UA	23.90	0.48	
6	Kemp El Paso	Dist. UA	13.80	4.16	
7	Latta El Paso	Dist. UA	13.80	4.16	
8	Lomaland El Paso	Dist. UA	13.80	4.16	
9	McClure Las Cruces, NM	Dist. UA	23.90	4.16	
10	Melendres Las Cruces, NM	Dist. UA	23.90	4.16	
11	Mesilla Park Mesilla Park, NM	Dist. UA	23.90	4.16	
12	Mission El Paso	Dist. UA	13.80	4.16	
13	Missouri Las Cruces, NM	Dist. UA	23.90	4.16	
14	Morningside El Paso	Dist. UA	13.80	4.16	
15	Mountain El Paso	Dist. UA	13.80	4.16	
16	Mulberry Upper Valley	Dist. UA	13.80	4.16	
17	Nevada Las Cruces, NM	Dist. UA	23.90	4.16	
18	Nevins Nevins	Dist. UA	23.90	4.16	
19	Newell Newell	Dist. UA	13.80	2.40	
20	Newtex Upper Valley	Dist. UA	23.90	4.16	
21	Octavia El Paso	Dist. UA	13.80	4.16	
22	Parkdale El Paso	Dist. UA	13.80	4.16	
23	Prison El Paso	Dist. UA	23.90	2.40	
24	Railroad El Paso	Dist. UA	13.80	2.40	
25	Ranchland El Paso	Dist. UA	13.80	4.16	
26	Range New Mexico	Dist. UA	24.90	13.20	
27	River Upper Valley	Dist. UA	13.80	4.16	
28	Rosedale El Paso	Dist. UA	13.80	4.16	
29	Sierra Blanca Sierra Blanca	Dist. UA	69.00	23.90	
30	Sierra Blanca Sierra Blanca	Dist. UA	23.90	4.16	
31	Summit El Paso	Dist. UA	13.80	4.16	
32	UTEP El Paso	Dist. UA	13.80	4.16	
33	Van Horn Van Horn	Dist. UA	23.90	4.16	
34	Vinton New Mexico	Dist. UA	23.90	4.16	
35	Water Trtmnt El Paso	Dist. UA	13.80	2.40	
36	Westside Las Cruces, NM	Dist. UA	23.90	4.16	
37	White Upper Valley	Dist. UA	13.80	4.16	
38	Ysleta El Paso	Dist. UA	13.80	4.16	
39					
40	300 to 999 kVA				

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	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					
2	Chevron Pipeline New Mexico	Dist. UA	23.90	2.40	
3	Dona Ana New Mexico	Dist. UA	23.90	4.16	
4	Fort Hancock Hudspeth County	Dist. UA	24.90	4.16	
5	La Mesa New Mexico	Dist. UA	23.90	4.16	
6	La Posta New Mexico	Dist. UA	23.90	4.16	
7	Salem New Mexico	Dist. UA	24.40	4.16	
8	Tornillo Lower Valley	Dist. UA	24.40	4.16	
9	Wilson El Paso	Dist. UA	13.80	2.40	
10					
11	300 kVA (Distribution Racks)				
12					
13	Acala Hudspeth County	Dist. UA	23.90	2.40	
14	Allamore Hudspeth County	Dist. UA	23.90	2.40	
15	Camp 90 Hudspeth County	Dist. UA	23.90	2.40	
16	Country Club Anthony, NM	Dist. UA	13.80	2.40	
17	Eagler Flats Hudspeth County (Dees)	Dist. UA	23.90	2.40	
18	Faskin Hudspeth County	Dist. UA	23.90	2.40	
19	Gill-Neely Hudspeth County (Maverick)	Dist. UA	23.90	2.40	
20	Love Hudspeth County	Dist. UA	23.90	2.40	
21	Riverside Hudspeth County	Dist. UA	23.90	2.40	
22					
23					
24	PORTABLE SUBSTATIONS				
25	(All sizes)				
26	Mobile Substation	Dist. UA	13.80	0.48	
27	Mobile Substation	Dist. UA	115.00	13.80	
28	Mobile Substation	Dist. UA	115.00	13.80	
29	Mobile Substation	Dist. UA	69.00	2.40	
30	Mobile Substation No. 2	Dist. UA	24.90	2.40	
31	Mobile Substation No. 3	Dist. UA	13.80	2.40	
32					
33	SPARE TRANSFORMERS	N/A			
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
						3
13	2					4
30	1					5
261	1					6
8	1					7
54	2					8
30	1					9
308	1					10
400	2					11
30	1					12
30	1	1				13
100	1					14
100	1					15
50	2					16
10	3					17
80	2					18
10	3					19
						20
70	2					21
60	2					22
400	2					23
30	3					24
43	2					25
8	1					26
3	3					27
125	1					28
30	1					29
2	1					30
1	1					31
12	1					32
13	1					33
60	2					34
20	1					35
20	1					36
5	2					37
600	3					38
12	1					39
50	2					40

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)	
100	1					1
13	1					2
20	1					3
15	1					4
50	2					5
30	1					6
30	1					7
2	1					8
100	1					9
30	1					10
40	2					11
6	1					12
120	2					13
20	1					14
5	2					15
30	1					16
24	1					17
60	2					18
100	1					19
90	3					20
130	3					21
30	1	1				22
230	1					23
112	1					24
6	1					25
5	1					26
10	1					27
112	1					28
10	1					29
112	1					30
112	1					31
10	1					32
112	1					33
20	1					34
125	1					35
175	1					36
117	1					37
117	1					38
17	1					39
17	1					40

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/09/2012	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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
220	1					1
30	1					2
10	3					3
10	2					4
5	1					5
30	1					6
50	1					7
13	1					8
348	1	1				9
200	2					10
11	1					11
10	1					12
14	1					13
50	1					14
4	1					15
20	1					16
3	1					17
						18
8	2					19
30	1					20
30	1					21
78	3					22
25	1					23
11	3					24
60	2					25
100	1					26
55	2					27
30	1					28
30	1					29
60	2					30
30	1					31
30	2					32
10	3					33
60	2					34
60	2					35
30	1					36
60	2					37
30	1					38
50	1					39
100	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	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)	
1	1					1
5	1					2
5	1					3
3	3					4
	1					5
2	1					6
2	1					7
4	2					8
2	1					9
3	3					10
2	1					11
5	1					12
3	1					13
3	2					14
2	1					15
3	2					16
2	1					17
2	1					18
3	1					19
3	2					20
2	1					21
3	2					22
3	1					23
2	3					24
4	2					25
8	3					26
1	1					27
2	1					28
18	1					29
1	1					30
4	2					31
4	1					32
3	4					33
3	1					34
4	1					35
3	1					36
2	1					37
3	4					38
						39
						40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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

Schedule Page: 426 Line No.: 3 Column: a

Afton substation is a switching transmission substation. The Company does not own the transformers on site.

Schedule Page: 426 Line No.: 20 Column: a

Biggs substation is a switching distribution substation. The Company does not own the transformers on site.

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				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
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38				
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