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** 2013/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 2013/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	Senior Vice President & CFO

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	/ /

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)*
/s/ Nathan T. Hirschi	/s/ Nathan T. Hirschi	04/09/2014
02 Title Senior Vice President & CFO		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

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".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* / /	Year/Period of Report End of 2013/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
Senior Vice President & CFO
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

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	/ /	End of 2013/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
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 Energy Services, Inc. (“MiraSol”), formerly a wholly owned subsidiary, provided energy efficiency products and discontinued these activities in 2002. The Company dissolved MiraSol in the fourth quarter of 2013. At the time it was dissolved, MiraSol’s net assets and stockholders’ equity totaled less than $0.1 million.

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	/ /	End of 2013/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chief Executive Officer	Thomas V. Shockley III	622,115
2	Executive Vice President	David G. Carpenter	358,852
3	Executive Vice President	Hector R. Puente	311,495
4	Senior Vice President - General Counsel		
5	and Chief Compliance Officer	Mary E. Kipp	307,928
6	Senior Vice President - Corporate Planning		
7	and Development	Rocky R. Miracle	280,192
8	Senior Vice President and Chief Financial Officer	Nathan T. Hirschi	242,993
9	Senior Vice President - Operations	Steven T. Buraczyk	234,156
10	Senior Vice President - Human Resources		
11	and Customer Care	William A. Stiller	231,154
12	Vice President - Power Generation	Andres R. Ramirez	238,204
13	Vice President - Transmission and Distribution		
14	and System Operations and Planning	Robert C. Doyle	223,516
15	Vice President - Treasurer	Steven P. Busser	218,631
16	Vice President - Community Outreach	Guillermo Silva, Jr.	151,541
17	Vice President - Power Marketing and Fuels		
18	and Resource and Delivery Planning	David C. Hawkins	155,768
19	Corporate Secretary	Jessica M. Goldman	112,472
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Schedule Page: 104 Line No.: 2 Column: b

On October 3, 2013, the Company appointed David G. Carpenter as Executive Vice President. Mr. Carpenter had been Senior Vice President and Chief Financial Officer since August 2009.

Schedule Page: 104 Line No.: 3 Column: b

On October 3, 2013, the Company appointed Hector R. Puente as Executive Vice President. Mr. Puente had been Senior Vice President and Chief Operations Officer since June 2012.

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

On October 3, 2013, the Company appointed Nathan T. Hirschi as Senior Vice President and Chief Financial Officer. Mr. Hirschi had been the Company's Vice President and Controller since March 2010.

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

On October 3, 2013, the Company appointed Steven T. Buraczyk as Senior Vice President of Operations. Mr. Buraczyk had been the Company's Vice President of Regulatory Affairs since April 2013. Prior to April 2013, Mr. Buraczyk had been Vice President of Power Marketing and Fuels and Resource and Delivery Planning since August 2012.

Schedule Page: 104 Line No.: 11 Column: b

On October 3, 2013, the Company appointed William A. Stiller as Senior Vice President, Human Resources and Customer Care. Mr. Stiller had been the Company's Vice President and Chief Human Resources Officer since January 2013.

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

On March 14, 2013, the Company appointed Guillermo Silva, Jr. as Vice President of Community Outreach. Mr. Silva had been Corporate Secretary since February 2006.

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

On April 15, 2013, the Company appointed David C. Hawkins as Vice President of Power Marketing and Fuels and Resource and Delivery Planning. Mr. Hawkins had been Director of Generation Operations since October 2011.

Schedule Page: 104 Line No.: 19 Column: b

On March 14, 2013, the Company appointed Jessica M. Goldman as Corporate Secretary. Ms. Goldman had been Attorney - Corporate and Securities since January 2012.

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	/ /	End of 2013/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, LLC
6		123 W. Mills, Suite 610
7		El Paso, Texas 79901
8		
9	James W. Cicconi - Director***	AT&T, Inc.
10		1120 20th Street, N.W., Suite 1000
11		Washington, D.C. 20036
12		
13	Edward Escudero - Director	High Desert Capital, LLC
14		6080 Surety Drive
15		El Paso, Texas 79905
16		
17	James W. Harris - Director***	OP Food Products, LLC and
18		Harris Financial Advisors, LLC
19		Post Office Box 38
20		Manns Harbor, North Carolina 27953
21		
22	Patricia Z. Holland-Branch - Director	The Facilities Connection, Inc.
23		240 East Sunset
24		El Paso, Texas 79922
25		
26	Woodley L. Hunt - Director	Hunt Companies, Inc.
27		4401 N. Mesa Street, Suite 201
28		El Paso, Texas 79901
29		
30	Michael K. Parks - Director and	El Paso Electric Company
31	Chairman of the Board***	100 N. Stanton
32		El Paso, Texas 79901
33		
34	Thomas V. Shockley III - Director and	El Paso Electric Company
35	CEO	100 N. Stanton
36		El Paso, Texas 79901
37		
38	Eric B. Siegel - Director**	11100 Santa Monica Blvd., Suite 2000
39		Los Angeles, California 90025
40		
41	Stephen N. Wertheimer - Director***	W Capital Partners
42		One East 52nd Street
43		New York, New York 10022
44		
45	Charles A. Yamarone - Director	Houlihan Lokey
46		10250 Constellation Blvd., 5th Floor
47		Los Angeles, California 90067
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	/ /	End of 2013/Q4

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

Does the respondent have formula rates?

[X] Yes

[ ] 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	/ /	End of 2013/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)?

[X] Yes

[ ] 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	20130806-5060	08/05/2013	ER08-742-000	2013 Annual Update	18
2		08/06/2013			
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Schedule Page: 1061 Line No.: 1 Column: d

The 2013 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	/ /	End of 2013/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. On January 14, 2014, the Company and Rio Grande Resouces Trust ("RGRT") entered into a second amended and restated credit agreement related to the revolving credit facility ("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 agreement, the Company has available $300 million and the ability to increase the RCF by up to $100 million (up to a total of $400 million) upon the satisfaction of certain conditions, more fully set forth in the agreement, including obtaining commitments from lenders or third party financial institutions. The RCF has a term ending January 2019. The Company may extend the maturity date up to two times, in each case for an additional one year period upon the satisfaction of certain conditions. Authorization for this transaction was received in FERC Docket No. ES 13-59-000 and New Mexico Public Regulation Commission ("NMPRC") Case No. 13-00317-UT.

7. Changes in Articles of Incorporation:

   None

8. Important Wage Scale Changes:

Base salaries for non-union employees were increased by an average of approximately 3.5% effective in January 2013 compared to 2012 through the merit award process. The annual effect of this increase was approximately $1.6 million. Base salaries for union employees under contract were increased by 3.0% effective in September 2013 compared to 2012. The annual effect of this increase was approximately $0.8 million.

9. Materially Important Legal Proceedings (see also Notes B, I and J 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, the Company 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.

Fuel Reconciliation Proceeding. On September 27, 2013, the Company filed an application with the Public Utility Commission of Texas (the "PUCT"), designated as Docket No. 41852, to reconcile $545.3 million of fuel and purchased power expenses incurred during the 45-month period from July 1, 2009 through March 31, 2013. The fuel reconciliation requests to recover $3.4 million of rewards for Palo Verde operations. Hearings in the fuel reconciliation have been suspended as the parties in the case seek to negotiate a settlement. The Company is unable to predict the outcome of these settlement negotiations. A final order must be issued by September 26, 2014.

10. Materially Important Transactions:

None

11. Reserved

12. Important changes during the year:

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 March 14, 2013, the Company appointed Guillermo Silva, Jr. as Vice President of Community Outreach. Mr. Silva had been Corporate Secretary since February 2006.

On March 14, 2013, the Company appointed Jessica M. Goldman as Corporate Secretary. Ms. Goldman had been Attorney - Corporate and Securities since January 2012.

On April 15, 2013, the Company appointed David C. Hawkins as Vice President of Power Marketing and Fuels and Resource and Delivery Planning. Mr. Hawkins had been Director of Generation Operations since October 2011.

On October 3, 2013, the Company appointed Nathan T. Hirschi as Senior Vice President and Chief Financial Officer. Mr. Hirschi had been the Company's Vice President and Controller since March 2010.

On October 3, 2013, the Company appointed Steven T. Buraczyk as Senior Vice President of Operations. Mr. Buraczyk had been the Company's Vice President of Regulatory Affairs since April 2013. Prior to April 2013, Mr. Buraczyk had been Vice President of Power Marketing and Fuels and Resource and Delivery Planning since August 2012.

On October 3, 2013, David G. Carpenter, formerly Senior Vice President and Chief Financial Officer, was appointed Executive Vice President.

On October 3, 2013, Hector R. Puente, formerly Senior Vice President and Chief Operations Officer, was appointed Executive Vice President.

On October 3, 2013, the Company appointed William A. Stiller as Senior Vice President, Human Resources and Customer Care. Mr. Stiller had been the Company’s Vice President and Chief Human Resources Officer since

January 2013.

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	/ /	End of 2013/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	3,937,846,897	3,722,491,248
3	Construction Work in Progress (107)	200-201	282,646,861	287,357,626
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,220,493,758	4,009,848,874
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,069,281,349	2,022,997,765
6	Net Utility Plant (Enter Total of line 4 less 5)		2,151,212,409	1,986,851,109
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)		189,389,905	191,084,821
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	74,610,066	69,700,908
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		114,779,839	121,383,913
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,265,992,248	2,108,235,022
15	Utility Plant Adjustments (116)		762,842	1,065,091
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		405,743	405,743
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	0	19,690
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)		1,554,750	1,295,222
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		221,440,666	194,467,189
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)		223,401,159	196,187,844
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		24,805,566	109,887,377
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		413,172	823,110
38	Temporary Cash Investments (136)		373,325	346,591
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		47,116,799	46,443,714
41	Other Accounts Receivable (143)		715,577	1,469,376
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,261,241	2,906,025
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	1,297,394	1,394,321
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	44,688,673	40,975,180
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	-34,975	-12,331

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	/ /	End of 2013/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	-8,972	433
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)		8,398,836	9,656,500
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		5,320	5,154
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		19,774,000	17,888,000
62	Miscellaneous Current and Accrued Assets (174)		796,962	908,009
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)		146,080,436	226,879,409
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,914,584	12,648,755
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	137,672,469	129,456,890
73	Prelim. Survey and Investigation Charges (Electric) (183)		4,904,452	3,260,291
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)		-182,614	-159,534
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	6,834,145	5,289,223
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)		19,230,934	20,116,858
82	Accumulated Deferred Income Taxes (190)	234	204,266,691	224,380,335
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		384,640,661	394,992,818
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,020,877,346	2,927,360,184

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	/ /	end of 2013/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	65,695,588	65,562,893
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)		302,273,508	299,068,355
7	Other Paid-In Capital (208-211)	253	2,205,552	1,939,126
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	1,006,809,842	959,965,047
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	-3,886,045
13	(Less) Reaquired Capital Stock (217)	250-251	424,646,957	424,646,957
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	2,611,733	-66,084,002
16	Total Proprietary Capital (lines 2 through 15)		954,608,327	831,577,478
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	700,000,000	700,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,514,806	3,600,354
24	Total Long-Term Debt (lines 18 through 23)		889,620,194	889,534,646
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)		134,666,386	224,859,420
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		581,752	581,752
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)		65,213,986	62,783,836
35	Total Other Noncurrent Liabilities (lines 26 through 34)		310,462,124	398,225,008
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		61,794,541	61,580,835
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		5,858,436	5,411,419
42	Taxes Accrued (236)	262-263	20,281,174	21,061,785
43	Interest Accrued (237)		10,280,428	10,218,008
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	/ /	end of 2013/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)		-586,267	-207,529
48	Miscellaneous Current and Accrued Liabilities (242)		17,659,332	16,791,631
49	Obligations Under Capital Leases-Current (243)		16,261,519	24,063,732
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)		131,549,163	138,919,881
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		13,345,219	8,839,182
57	Accumulated Deferred Investment Tax Credits (255)	266-267	23,640,795	24,343,915
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	15,164,102	14,849,618
60	Other Regulatory Liabilities (254)	278	55,544,263	55,875,360
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)		548,208,981	492,091,591
64	Accum. Deferred Income Taxes-Other (283)		78,734,178	73,103,505
65	Total Deferred Credits (lines 56 through 64)		734,637,538	669,103,171
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,020,877,346	2,927,360,184

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	890,361,710	852,881,170		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	520,616,951	484,908,871		
5	Maintenance Expenses (402)	320-323	61,068,032	60,339,110		
6	Depreciation Expense (403)	336-337	70,251,454	70,060,317		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	-1,225,519	-1,309,127		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,682,899	7,183,006		
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)		152,184	152,184		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	57,747,007	57,442,668		
15	Income Taxes - Federal (409.1)	262-263	-2,122,021	1,347,316		
16	- Other (409.1)	262-263	-128,693	558,767		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	120,301,627	130,696,026		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	79,675,531	89,722,414		
19	Investment Tax Credit Adj. - Net (411.4)	266	-737,115	-1,192,320		
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)		8	20		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		5,867,284	5,164,981		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		759,798,551	725,629,365		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		130,563,159	127,251,805		

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
890,361,710	852,881,170					2
						3
520,616,951	484,908,871					4
61,068,032	60,339,110					5
70,251,454	70,060,317					6
-1,225,519	-1,309,127					7
7,682,899	7,183,006					8
						9
						10
						11
152,184	152,184					12
						13
57,747,007	57,442,668					14
-2,122,021	1,347,316					15
-128,693	558,767					16
120,301,627	130,696,026					17
79,675,531	89,722,414					18
-737,115	-1,192,320					19
						20
						21
8	20					22
						23
5,867,284	5,164,981					24
759,798,551	725,629,365					25
130,563,159	127,251,805					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)		130,563,159	127,251,805		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		763,894	14,045		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		476,225	1,679		
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	-8,264	-34,166		
37	Interest and Dividend Income (419)		6,220,079	6,141,756		
38	Allowance for Other Funds Used During Construction (419.1)		10,008,517	9,426,546		
39	Miscellaneous Nonoperating Income (421)		6,380,053	7,108,557		
40	Gain on Disposition of Property (421.1)		111,600	1,369,757		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		22,999,654	24,024,816		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			23,483		
44	Miscellaneous Amortization (425)		302,248	302,248		
45	Donations (426.1)		2,249,257	1,131,199		
46	Life Insurance (426.2)		164,072	16,771		
47	Penalties (426.3)		15,209	74,323		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		668,952	680,729		
49	Other Deductions (426.5)		42,151	2,785,026		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,441,889	5,013,779		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	10,410	10,342		
53	Income Taxes-Federal (409.2)	262-263	4,110,094	2,021,784		
54	Income Taxes-Other (409.2)	262-263	182,643			
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	807,851	6,813,089		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,034,893	5,824,779		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)		-33,995	-33,996		
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,110,100	3,054,432		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		15,447,665	15,956,605		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		56,687,739	52,844,578		
63	Amort. of Debt Disc. and Expense (428)		1,061,218	908,132		
64	Amortization of Loss on Reaquired Debt (428.1)		885,924	878,710		
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)		651,212	930,373		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		6,055,220	5,573,683		
70	Net Interest Charges (Total of lines 62 thru 69)		53,230,873	49,988,110		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		92,779,951	93,220,300		
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)		92,779,951	93,220,300		

Schedule Page: 114 Line No.: 36 Column: c

MiraSol Energy Services, Inc. (“MiraSol”), a formerly wholly owned subsidiary, provided energy efficiency products and discontinued these activities in 2002. The Company dissolved MiraSol in the fourth quarter of 2013. At the time it was dissolved, MiraSol’s net assets and stockholders’ equity totaled less than $0.1 million.

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	/ /	End of 2013/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		959,965,047	905,600,092
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)		92,788,215	93,254,466
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	Class Common Stock $1 par value		-42,049,111	(38,889,511)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-42,049,111	(38,889,511)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		-3,894,309	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,006,809,842	959,965,047
	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	/ /	End of 2013/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)		1,006,809,842	959,965,047
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-3,886,045	(3,851,879)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-8,264	(34,166)
51	(Less) Dividends Received (Debit)			
52	Transfers to Acct 216, Unapprop. Undistrib. Subsidiary Earnings		3,894,309	
53	Balance-End of Year (Total lines 49 thru 52)			(3,886,045)

Schedule Page: 118 Line No.: 52 Column: c

MiraSol Energy Services, Inc. ("MiraSol"), a formerly wholly owned subsidiary, provided energy efficiency products and discontinued these activities in 2002. The Company dissolved MiraSol in the fourth quarter of 2013. At the time it was dissolved, MiraSol's net assets and stockholders' equity totaled less than $0.1 million.

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	/ /	End of 2013/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)	92,779,951	93,220,300
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	70,251,454	70,060,317
5	Amortization of Other	19,820,554	19,285,480
6	Amortization of Nuclear Fuel	42,769,529	43,108,954
7			
8	Deferred Income Taxes (Net)	40,399,053	41,961,920
9	Investment Tax Credit Adjustment (Net)	-703,120	-1,158,324
10	Net (Increase) Decrease in Receivables	-2,450,236	13,448,130
11	Net (Increase) Decrease in Inventory	-3,695,960	-1,972,079
12	Net (Increase) Decrease in Allowances Inventory	22,644	45,814
13	Net Increase (Decrease) in Payables and Accrued Expenses	11,771,317	-1,116,877
14	Net (Increase) Decrease in Other Regulatory Assets	-2,919,871	10,945,693
15	Net Increase (Decrease) in Other Regulatory Liabilities	-3,595,215	2,538,130
16	(Less) Allowance for Other Funds Used During Construction	10,008,517	9,426,546
17	(Less) Undistributed Earnings from Subsidiary Companies	-8,264	-34,166
18	Other (provide details in footnote):	2,570,949	1,160,385
19			
20	Deferred Charges and Credits	-4,997,865	-6,043,077
21	Net (Increase) Decrease in Prepayments and Other	-4,295,263	-2,670,066
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	247,727,668	273,422,320
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-253,474,672	-217,386,797
27	Gross Additions to Nuclear Fuel	-36,097,252	-51,582,298
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-10,008,517	-9,426,546
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-279,563,407	-259,542,549
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	111,600	1,757,476
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	11,426	-52,046
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 El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/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)	-65,491,330	-107,704,536
54	Investment in Decommissioning Trust Fund (Sales and Maturities)	56,148,015	98,542,024
55	Other (provide details in footnote):	5,767,572	632,035
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-283,016,124	-266,367,596
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		242,217,000
62	Preferred Stock		
63	Common Stock		
64	Other: Financing and Other Capital Lease Obligations - Proceeds	44,884,164	234,574,706
65	Exercise of Stock Options	191,700	414,087
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)	45,075,864	477,205,793
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-92,535,000
74	Preferred Stock		
75	Common Stock		
76	Other Financing Activities	-945,522	-5,288,624
77	Financing and Capital Lease Obligations	-52,686,377	-245,799,264
78	Net Decrease in Short-Term Debt (c)		
79	Tax Benefits from Long-Term Incentive Plans	428,587	1,101,233
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-42,049,111	-38,889,511
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-50,176,559	95,794,627
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-85,465,015	102,849,351
87			
88	Cash and Cash Equivalents at Beginning of Period	111,057,078	8,207,727
89			
90	Cash and Cash Equivalents at End of period	25,592,063	111,057,078

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

	2013	2012
Other:		
Net Gain on Sale of Property	$ (111,600)	$(1,369,757)
Net (Gain)/Loss on Equity Investments	(553,401)	1,041,887
Amortization of Unearned Compensation	3,647,661	1,766,219
Unrealized Gains on Investments in Debt Securities	(259,528)	(175,246)
Other Operating Activities	(152,183)	(102,718)
Total	$ 2,570,949	$ 1,160,385

Schedule Page: 120 Line No.: 55 Column: a

	2013	2012
Other:		
Customer Advances for Construction	$ 4,506,038	$(352,024)
Property Salvage Value	1,261,534	984,059
Total	$ 5,767,572	$ 632,035

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

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

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 2013 Form 10-K filed by El Paso Electric Company with the Securities and Exchange Commission. Notes A through N of the regulatory-basis financial statements are from the 2013 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 N 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 Financial Accounting Standards Board ("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.

GAAP requires earnings per share information on the income statement and 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.		2013	2012
	Assets and Other Debits (Pages 110-111)		
2	Utility plant	$ (861,298)	$ (864,579)
5	Accumulated provision for depreciation, amortization and depletion	(855,193)	(860,515)
11	Nuclear fuel under capital lease	(1,204)	(1,164)
12	Accumulated provision for amortization of nuclear fuel	1,210	664
15	Utility plant adjustments	(763)	(1,065)
18	Nonutility property	(406)	(406)
21	Investment in subsidiary companies	0	(20)
24	Other investments	(1,555)	(1,295)
28	Other special funds	(221,441)	(194,467)
67	Total current and accrued assets	5,746	(937)
84	Total deferred debits	(7,652)	(54,228)
	Liabilities and Other Credits (Pages 112-113)		
2	Common stock issued	64	42
6	Premium on capital stock	12,170	11,926
7	Other paid-in capital	(2,205)	(1,939)
10	Capital stock expense	(341)	(341)
11	Retained earnings	(21,145)	(20,834)
12	Unappropriated undistributed subsidiary earnings	0	3,886
24	Total long-term debt	110,000	110,000
35	Total other noncurrent liabilities	(310,462)	(398,225)
54	Total current and accrued liabilities	5,972	12,829
65	Total deferred credits	(29,325)	23,664
	Statements of Income for the Year (Pages 114-117)		
25	Total utility operating expenses	$ (35,072)	$ (41,406)
26	Net utility operating income	35,072	41,406
60	Net other income and deductions	(1,132)	(1,853)
70	Net interest charges	(5,519)	(5,052)
-	Income tax expense	43,655	46,979
78	Net income	(4,197)	(2,374)
	Statement of Retained Earnings (Pages 118-119)		
1	Balance – beginning of period	$ (20,834)	$ (18,426)
48	Total retained earnings	(21,145)	(20,834)
	Statement of Cash Flows (Pages 120-121)		
22	Net cash provided by (used in) operating activities	$ (252)	$ (314)
57	Net cash provided by (used in) investing activities	252	314
	Statement of Accumulated Comprehensive Income, Comprehensive Income and Hedging Activities (Page 122a-122b)		
9	Other comprehensive income	$ 0	$ (1,484)

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, 2013 and 2012 consist of the following (in thousands):

	2013	2012
Cash and Cash Equivalents:		
Cash (131)	$ 24,806	$ 109,887
Working funds (135)	413	823
Temporary cash investments (136)	373	347
Cash and cash equivalents at end of period	$ 25,592	$ 111,057
Amortization of Other:		
ARO depreciation (403.1)	$ (1,225)	$ (1,309)
Other utility plant (404)	7,683	7,183
Regulatory assets (407.3)	152	152
ARO accretion expense (411.10)	5,867	5,165
Miscellaneous amortization (425)	302	302
Debt expense (428)	1,061	908
Loss on reacquired debt (428.1)	886	879
Interest rate lock losses	411	385
RCF issuance costs	179	69
Dry cask storage amortization	1,567	1,877
Coal reclamation amortization	1,183	1,182
New Mexico rate case expense amortization	-	252
Texas rate case expense amortization	1,755	2,240
	$ 19,821	$ 19,285

Utility Plant Adjustments

The following table summarizes amounts reflected as Utility Plant Adjustments for the New Mexico jurisdiction as of December 31, 2013 and 2012 (in thousands):

		2013 Activity		
	December 31, 2012	Additions (Debits)	Amortization (Credits)	December 31, 2013
New Mexico (a)				
Utility Plant Adjustment	$ 17,848	$ –	$ –	$ 17,848
Accumulated Amortization	(16,783)	–	(302)	(17,085)
	$ 1,065	$ –	$ (302)	$ 763

(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 is amortizing this asset over the original depreciable lives of the respective production units.

Accounting and Reporting for New Electric Storage Operations

The Company does not have electric storage assets and therefore does not have any operation and maintenance expense or purchased power expense to report in accordance with the interim guidance in FERC Docket No. AI14-1-000 issued on February 20, 2014, for reporting energy storage assets, operation and maintenance expense and purchased power expense in the Notes to Financial Statements.

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.

Dissolution of Subsidiary. MiraSol Energy Services, Inc. ("MiraSol"), the Company's wholly owned subsidiary, provided energy efficiency products and discontinued these activities in 2002. MiraSol had no material effect on the Company's previously reported regulatory-basis financial statements for the year ended December 31, 2012. The Company dissolved MiraSol in the fourth quarter of 2013. MiraSol's net assets and stockholders' equity totaled less than $0.1 million and the dissolution of MiraSol had no material effect on the Company's regulatory-basis financial statements for the twelve months ended December 31, 2013.

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.

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 generally 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 2013 and 2012 was 2.61% and 2.64%, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its 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 D.

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 rates used in 2013 and 2012 were 8.10% and 8.53%, respectively. 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, 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 E. 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 the decommissioning trust funds which are reflected 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 N.

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 N.

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 Notes B and 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 (or "Accrued Utility 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 and recorded as Accrued Utility Revenues. 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 2013 and 2012 are as follows (in thousands):

	2013	2012
Balance at beginning of year	$ 2,906	$ 3,015
Additions:		
Charged to costs and expense	2,098	3,087
Recovery of previous write-offs	1,929	2,041
Uncollectible receivables written off	4,672	5,237
Balance at end of year	$ 2,261	$ 2,906

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. Certain temporary differences are accorded flow-through treatment by the Company's regulators and impact the Company's effective tax rate. FASB guidance requires that rate-regulated companies record deferred income taxes for temporary differences accorded flow-through treatment at the direction of the regulatory commission. The resulting deferred tax assets and liabilities are recorded at the expected cash flow to be reflected in future rates. Because the Company's regulators have consistently permitted the recovery of tax effects previously flowed-through earnings, the Company has recorded regulatory liabilities and assets offsetting such deferred tax 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 H.

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 F.

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

Reclassification. Certain amounts in the regulatory-basis financial statements for 2012 have been reclassified to conform with the 2013 presentation.

B. 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 (sales for resale) transactions, transmission service and compliance with federally-mandated reliability standards. The decisions of the PUCT, the NMPRC and the FERC are subject to judicial review.

Texas Regulatory Matters

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

On April 17, 2012, the Council approved the settlement of the Company's 2012 Texas retail rate case and fuel reconciliation in PUCT Docket No. 40094. The PUCT issued a final order approving the settlement on May 23, 2012.

Under the terms of the settlement, among other things, the Company agreed to:

- A reduction in its non-fuel base rates of $15 million annually, with the decrease being allocated primarily to Texas retail commercial and industrial customer classes. The rate decrease was effective as of May 1, 2012;
- Revised depreciation rates for the Company's gas-fired generating units and for transmission and distribution plant that lower depreciation expense by $4.1 million annually;
- Continuation of the 10.125% return on equity for the purpose of calculating the allowance for funds used during construction; and
- two-year amortization of rate case expenses, none of which will be included in future regulatory proceedings.

As part of the settlement, the Company agreed to withdraw its request to reconcile fuel costs for the period from July 1, 2009 through September 30, 2011 and submit a future fuel reconciliation request covering the period beginning July 1, 2009 and ending no later than June 30, 2013 by December 31, 2013 or as part of its next rate case, if earlier. The settlement also provides for the continuation of the energy efficiency cost recovery factor and the military base discount recovery factor. Both of these surcharges require annual filings to reconcile and revise the recovery factors.

Fuel and Purchased Power Costs. The Company's actual fuel costs, including purchased power energy costs, are recovered from customers through a fixed fuel factor. The PUCT has adopted a fuel cost recovery rule (the "Texas Fuel Rule") that allows the Company to seek periodic adjustments to its fixed fuel factor. 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 filed the following petition with the PUCT to refund 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 date the Company filed the petition and the date a final order was issued by the PUCT approving the refund to customers. The fuel cost over-recovery period represents the months in which the over-recoveries took place, and the refund period represents the billing month in which customers received the refund amounts shown, including interest:

Docket No.	Date Filed	Date Approved	Recovery Period	Refund Period	Refund Amount Authorized (In Thousands)
40622	August 3, 2012	September 28, 2012	January 2011- June 2012	September 2012	$ 6,600

The Company 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
40302	April 12, 2012	April 25, 2012	(18.5)%	May 2012
41803	September 9, 2013	September 23, 2013	12.2%	October 2013

Fuel Reconciliation Proceeding. On September 27, 2013, the Company filed an application with the PUCT, designated as Docket No. 41852, to reconcile $545.3 million of fuel and purchased power expenses incurred during the 45-month period from July 1, 2009 through March 31, 2013. The fuel reconciliation requests to recover $3.4 million of rewards for Palo Verde operations. Hearings in the fuel reconciliation have been suspended as the parties in the case seek to negotiate a settlement. The Company is unable to predict the outcome of these settlement negotiations. A final order must be issued by September 26, 2014.

Montana Power Station Approvals. The Company has received a Certificate of Convenience and Necessity ("CCN") authorization from the PUCT to construct the first two (of four) units of the Montana Power Station ("the MPS"). The Company also had to obtain air permits from state and federal regulatory agencies before it could begin construction. On January 22, 2014, the Texas Commission on Environmental Quality ("TCEQ") issued the required permit. The U.S. Environmental Protection Agency ("EPA") issued a draft permit for greenhouse gas ("GHG") in September 2013 and solicited public comment. The EPA considered comments filed in response to that proposal before issuing a final permit on March 25, 2014. Commenters have 30 days to challenge the EPA's decision before the U.S. EPA's Environmental Appeals Board. The Company believes that the type of facility planned at the MPS complies with all EPA regulations for granting a GHG permit and that the issues raised in the comments have previously been resolved in proceedings in other regions in favor of the grant of a permit. While the Company believes that this application demonstrates compliance with all applicable regulations, it cannot predict the timing or final outcome of this matter.

On September 6, 2013, the Company filed an application with the PUCT for issuance of a CCN to construct, own and operate two additional 88 MW natural gas-fired generating units designated as the MPS Units 3 and 4 in El Paso County, Texas. The case has been designated PUCT Docket No. 41763. Hearings in this case were held in February 2014. In accordance with PUCT rules, the final order must be issued by September 5, 2014.

The Company filed three transmission line CCN applications with the PUCT as part of the MPS Project:

- MPS to Caliente: a 115-kV transmission line from the MPS to the existing Caliente Substation in east El Paso. (PUCT Docket No. 41360)
- MPS In & Out: a 115-kV transmission line from the MPS to intersect with the existing Caliente - Coyote 115-kV transmission line. (PUCT Docket No. 41359)
- MPS to Montwood: a 115-kV transmission line from the MPS to the existing Montwood Substation in east El Paso. (PUCT Docket No. 41809)

The transmission CCN filings for both the MPS to Caliente and the MPS In & Out were filed on April 15, 2013, and the transmission CCN filing for the MPS to Montwood was filed on September 24, 2013. The Company is requesting to build these transmission lines to connect the new MPS to the electrical grid in order to meet increased customer growth and electric demand and to improve system reliability. A final order approving a unanimous settlement in the MPS to Caliente transmission CCN filing was received on March 10, 2014. Final orders in the transmission CCN filings for the MPS In & Out and the MPS to Montwood filings are expected no later than October 2014.

Other Required Approvals. The Company has obtained other required approvals for recovery of fuel costs through fixed fuel factors, other tariffs and approvals as required by the Public Utility Regulatory Act (the "PURA") and the PUCT.

New Mexico Regulatory Matters

2009 New Mexico Stipulation. On December 10, 2009, the NMPRC issued a final order conditionally approving the stipulated rates in NMPRC Case No. 09-00171-UT. The stipulated rates went into effect with January 2010 bills. The stipulated rates provide for an Efficient Use of Energy Factor Rate Rider to recover energy efficiency expenditures which requires an annual filing and approval of the related incentives and adjustment to the recovery factors.

Fuel and purchased power costs in New Mexico are recovered through a Fuel and Purchased Power Cost Adjustment Clause (the "FPPCAC"). On January 8, 2014, the NMPRC approved the continuation of the FPPCAC without modification in NMPRC Case No. 13-00380-UT. The Company recovers its investment in Palo Verde Unit 3 in New Mexico through the FPPCAC as purchased power using a proxy market price approved in the 2009 New Mexico rate stipulation.

2013 Annual Procurement Plan Pursuant to the Renewable Energy Act. On July 1, 2013, the Company filed its application for approval of its 2013 Annual Procurement Plan pursuant to the New Mexico Renewable Energy Act. On November 20, 2013, the NMPRC issued a final order approving the renewable procurement plan with modifications recommended by the Hearing Examiner. The plan sets out the Company's procurement of renewable resources and estimated costs for 2014 and 2015 to meet Renewable Portfolio Standards ("RPS") and resource diversity requirements. The approved plan provides for the RPS and diversity requirements for 2014 and 2015 to be met with a combination of previously approved resources and grants the Company's request for waiver for meeting the full RPS through 2015 due to reasonable cost threshold limits. The order also grants the Company's requested diversity variances for 2014 and 2015. Costs for purchases of renewable energy delivered to the Company are recovered through the FPPCAC and purchases of unbundled renewable energy credits are recovered through base rates.

Long-Term Purchased Power Agreement with Macho Springs. On November 21, 2012, the Company filed an application with the NMPRC requesting approval of a Long-Term Purchase Power Agreement (the "LTPPA") with Macho Springs Solar, LLC ("Macho Springs") to purchase energy from a 50 MW solar facility to be constructed by Macho Springs on the Company's New Mexico transmission system. The Company also sought approval of the recovery of costs associated with the LTPPA through the Company's FPPCAC. A final order approving the LTPPA and recovery through the FPPCAC was received May 1, 2013.

Montana Power Station Approvals. The Company has received a CCN authorization from the NMPRC to construct the first two (of four) units of the MPS. As discussed above, the Company must also obtain air permits from the TCEQ and EPA before it can begin construction. On September 6, 2013, the Company filed an application with the NMPRC for issuance of a CCN to construct, own and operate two additional 88 MW natural gas-fired generating units designated as the MPS Units 3 and 4 in El Paso County, Texas. The case has been designated NMPRC Case No. 13-00297-UT. No protests to the Company's application were filed and the hearing examiner issued a recommended decision to approve the Company's application on February 20, 2014. A final order is expected early in the second quarter of 2014.

Revolving Credit Facility, Issuance of Long-Term Debt and Guarantee of Debt. On October 30, 2013, the Company received approval in NMPRC Case No. 13-00317-UT to amend its current $300 million Revolving Credit Facility ("RCF") to include an option, subject to lender's approval, to expand the amount of the potential borrowings available under the facility to $400 million and extend the maturity date by up to four years; issue up to $300 million in new long-term debt; and to guarantee the issuance of up to $50 million of new debt by Rio Grande Resources Trust ("RGRT") to finance future purchases of nuclear fuel and to refinance existing debt obligations related to the financing of purchases of nuclear fuel.

On January 14, 2014, the Company and RGRT entered into a second amended and restated credit agreement related to 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 agreement, the Company has available $300 million and the ability to increase the RCF by up to $100 million (up to a total of $400 million) upon the satisfaction of certain conditions, more fully set forth in the agreement, including obtaining commitments from lenders or third party financial institutions. The RCF has a term ending January 2019. The Company may extend the maturity date up to two times, in each case for an additional one year period upon the satisfaction of certain conditions.

Other Required Approvals. The Company has obtained other required approvals for other tariffs, securities transactions, long-term resource plans, recovery of energy efficiency costs through a base rate rider and other approvals as required by the NMPRC.

Federal Regulatory Matters

Public Service Company of New Mexico's ("PNM") 2010 Transmission Rate Case. On October 27, 2010, PNM filed a Notice of Transmission Rate Change for transmission delivery services provided by PNM. These rates went into effect on June 1, 2011. The Company takes transmission service from PNM. On January 2, 2013, the FERC issued a letter order approving a unanimous stipulation and agreement. Pursuant to the stipulation, on January 31, 2013, PNM refunded $1.9 million for amounts that PNM collected since June 1, 2011 in excess of settlement rates. This amount was recorded in the fourth quarter of 2012 as a reduction of transmission expense.

Revolving Credit Facility, Issuance of Long-Term Debt and Guarantee of Debt. On September 30, 2013, the Company filed an application for approval to amend its current $300 million RCF to include an option, subject to lender's approval, to expand the amount of the potential borrowings available under the facility to $400 million and extend the maturity date by up to four years; issue up to $300 million in new long-term debt; and to guarantee the issuance of up to $50 million of new debt by RGRT to finance future purchases of nuclear fuel and to refinance existing debt obligations related to the purchase of nuclear fuel. The FERC issued an order approving the filing on November 15, 2013. The case was assigned to FERC Docket No. ES 13-59-000. As noted above, on January 14, 2014, the Company and RGRT entered into a second amended and restated credit agreement related to the RCF.

Other Required Approvals. The Company has obtained required approvals for rates and tariffs, securities transactions and other approvals as required by the FERC.

Department of Energy ("DOE"). The DOE regulates the Company's exports of power to the Comision 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 D for discussion of spent fuel storage and disposal costs.

Sales for Resale

The Company provides firm capacity and associated energy to the Rio Grande Electric Cooperative ("RGEC") pursuant to an ongoing contract with a two-year notice to terminate provision. The Company also provides network integrated transmission service to the 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 the RGEC.

C. 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, 2013	December 31, 2012
Regulatory assets			
Regulatory tax assets (a)	(b)	$ 110,030	$ 105,219
Final coal reclamation (e)	July 2016	4,290	5,473
Nuclear fuel postload daily financing charge	(c)	4,488	4,149
Texas energy efficiency	(d)	—	536
Texas 2012 rate case costs (e)	April 2014	581	2,335
Texas military base discount and recovery factor	(g)	759	2,116
New Mexico procurement plan costs	(f)	139	139
New Mexico renewable energy credits	(f)	4,833	4,033
New Mexico 2010 FPPCAC audit	(f)	433	433
New Mexico Palo Verde deferred depreciation	(b)	4,871	5,024
Undercollection of fuel revenues	(h)	7,248	—
Total regulatory assets		$ 137,672	$ 129,457
Regulatory liabilities			
Regulatory tax liabilities (a)	(b)	$ 50,488	$ 50,306
New Mexico energy efficiency	(d)	3,646	926
Texas energy efficiency	(d)	362	—
Overcollection of fuel revenues	(h)	1,048	4,643
Total regulatory liabilities		$ 55,544	$ 55,875

(a) No specific return on investment is required since related assets and liabilities offset.
(b) The amortization period for this asset is based upon the life of the associated assets or liabilities.
(c) This item is recovered through fuel recovery mechanisms.
(d) This item is recovered or credited through a recovery factor that is set annually.
(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.

D. 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, 2013 (in thousands):

	Gross Plant	Accumulated Depreciation	Net Plant
Nuclear production	$ 1,751,383	$ (1,189,614)	$ 561,769
Steam and other	670,149	(272,731)	397,418
Total production	2,421,532	(1,462,345)	959,187
Transmission	380,998	(198,022)	182,976
Distribution	937,265	(308,032)	629,233
General	128,391	(63,894)	64,497
Intangible	69,661	(36,988)	32,673
Total	$ 3,937,847	$ (2,069,281)	$ 1,868,566

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 years of 2012 and 2013 and for the next five years (in thousands):

2012	$ 7,183
2013	7,683
2014 (estimated)	7,372
2015 (estimated)	6,540
2016 (estimated)	5,980
2017 (estimated)	5,326
2018 (estimated)	3,713

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, 2013 and 2012 is as follows (in thousands):

	December 31, 2013		December 31, 2012	
	Palo Verde	Other	Palo Verde	Other
Electric plant in service	$ 1,751,383	$ 174,744	$ 1,734,906	$ 170,762
Accumulated depreciation	(1,189,614)	(131,989)	(1,182,430)	(127,055)
Construction work in progress	75,040	2,347	64,623	2,401
Total	$ 636,809	$ 45,102	$ 617,099	$ 46,108

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.

Nuclear Regulatory Commission ("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 now expire in 2045, 2046 and 2047, respectively.

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 and is required to maintain a minimum accumulation and 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, 2013, the Company's decommissioning trust fund had a balance of $214.1 million, which is above the target funding level. The Company monitors the status of its decommissioning funds and adjusts its deposits, if necessary.

Decommissioning costs are estimated every three years based upon engineering cost studies performed by outside engineers retained by APS. In December 2013, the Palo Verde Participants approved the 2013 Palo Verde decommissioning study (the "2013 Study"). The 2013 Study estimated that the Company must fund approximately $380.7 million (stated in 2013 dollars) to cover its share of decommissioning costs which was an increase in decommissioning costs of $23.3 million (stated in 2013 dollars) from the 2010 Palo Verde decommissioning study. However, because the cash flows from the 2013 Study were less than the inflated amounts from the 2010 Study, the effect of this change lowered the asset retirement obligation by $1.9 million and will lower annual expenses starting in January 2014. Although the 2013 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.

Spent Nuclear Fuel and Waste Disposal. Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "NWPA"), 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 by 1998. The DOE's obligations are reflected in a contract for Disposal of Spent Nuclear Fuel and/or High-Level Radioactive Waste (the "Standard Contract") with each nuclear power plant. The DOE failed to begin accepting spent nuclear fuel by 1998. APS (on behalf of itself and the other Palo Verde participants) filed a lawsuit for DOE's breach of the spent nuclear fuel contract in the U.S. Court of Federal Claims. The Court of Federal Claims ruled in favor of APS and in October 2010 awarded $30.0 million in damages to the Palo Verde participants for costs incurred through December 2006. 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. On December 19, 2012, APS, acting on behalf of itself and the participant owners of Palo Verde, filed a second breach of contract lawsuit against the DOE. This lawsuit seeks to recover damages incurred due to DOE's failure to accept Palo Verde's spent nuclear fuel for the period beginning January 1, 2007 through June 30, 2011.The lawsuit is presently pending in the Court of Federal Claims.

The DOE had planned to meet its disposal obligations by designing, licensing, constructing, and operating a permanent geologic repository at Yucca Mountain, Nevada. In March 2010, the DOE filed a motion to dismiss with prejudice its Yucca Mountain construction authorization application that was pending before the NRC. Several interested parties have intervened in the NRC proceeding, and the proceeding has not been conclusively decided by the NRC or the courts. Additionally, a number of interested parties have filed a variety of lawsuits in different jurisdictions around the country challenging the DOE's authority to withdraw the Yucca Mountain construction authorization application and NRC's cessation of its review of the Yucca Mountain construction authorization application. The cases have been consolidated into one matter at the D.C. Circuit. In August 2013, the D.C. Circuit ordered the NRC to resume its review of the application with available appropriated funds. The Company cannot predict when spent fuel shipments to the DOE will commence.

APS and the Company believe 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. The Company expects to incur significant costs for on-site spent fuel storage during the life of Palo Verde which 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.

The One-Mill Fee. In 2011, the National Association of Regulatory Utility Commissioners and the Nuclear Energy Institute challenged DOE's 2010 determination of the adequacy of the one tenth of a cent per kWh fee (the "one-mill fee") paid by the nation's commercial nuclear power plant owners pursuant to their individual obligations under the Standard Contract. This fee is recovered by the Company through applicable fuel adjustment clauses. In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit (the "D.C. Circuit") held that DOE failed to conduct a sufficient fee analysis in making the 2010 determination. The D.C. Circuit remanded the 2010 determination to the Secretary of the DOE ("Secretary") with instructions to conduct a new fee adequacy determination within six months. In February 2013, upon completion of DOE's revised one-mill fee adequacy determination, the court reopened the proceedings. On November 19, 2013, the D.C. Circuit ordered the Secretary to notify Congress of his intent to suspend collecting annual fees for nuclear waste disposal from nuclear power plant operators, as he is required to do pursuant to the NWPA and the court's order. On January 3, 2014, the Secretary notified Congress of his intention to suspend collection of the one-mill fee, subject to Congress' disapproval.

NRC Oversight of the Nuclear Energy Industry in the Wake of the Earthquake and Tsunami in Japan. 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. Following the March 11, 2011 earthquake and tsunami in Japan, the NRC established a task force to conduct a systematic and methodical review of NRC processes and regulations to determine whether the agency should make additional improvements to its regulatory system. On March 12, 2012, the NRC issued the first regulatory requirements based on the recommendations of the NRC's Near Term Task Force. With respect to Palo Verde, the NRC issued two orders requiring safety enhancements regarding: (1) mitigation strategies to respond to extreme natural events resulting in the loss of power at plants; and (2) enhancement of spent fuel pool instrumentation.

The NRC has issued a series of interim staff guidance documents regarding implementation of these requirements. Due to the developing nature of these requirements, the Company cannot predict the ultimate financial or operational impacts on Palo Verde or the Company; however, the NRC has directed nuclear power plants to implement the first tier recommendations of the NRC's Near Term Task Force. In response to these recommendations, Palo Verde expects to spend approximately $100 million for capital enhancements to the plant over the next several years (the Company's share is $15.8 million).

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 $13.6 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 $127.3 million, subject to an annual limit of $19.0 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 $60.4 million, with an annual payment limitation of approximately $9.0 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 $2.8 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 $9.8 million for the current policy period.

Four Corners

The Company owns a 7% interest in Units 4 and 5 at Four Corners. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other Four Corners participants. The 50-year participation agreement among the owners of Four Corners expires by its terms in July 2016. The Company has notified the other owners that it has decided to cease its participation in the plant by July 2016. The Company believes that it has better economic and cleaner alternatives for serving the energy needs of its customers than coal-fired generation. The Company has nevertheless agreed to work with the other owners and the Navajo Nation in an attempt to facilitate their efforts to extend the operation of the plant beyond July 2016 in a manner consistent with protecting the Company's ratepayers. In December 2013, the other owners executed a long-term extension of the coal supply agreement for the plant through 2031. The Company did not sign the extension and APS has agreed to assume the resulting 7% shortfall and has also expressed an interest in acquiring the Company's interest in Four Corners.

E. Accounting for Asset Retirement Obligations

The Company complies with FERC Order No. 631 guidance 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 retirement obligations 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 2013 ARO liability for Palo Verde is based upon the estimated cost of decommissioning the plant from the 2013 Palo Verde decommissioning study. See Note D. 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 maintains 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, 2013 is $214.1 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 December 2013, the Company implemented the 2013 Palo Verde decommissioning study, and as a result, revised its ARO related to Palo Verde to decrease its estimated cash flows from the 2010 Study to the 2013 Study (see Note D). The assumptions used to calculate the Palo Verde 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 total ARO liability from January 1, 2012 through December 31, 2013, including the effects of each year's estimate revisions, is presented below. In 2013, the estimate revision includes a change to the probability of extending Four Corners' operating term and decreases in the estimated cash flows related to Palo Verde's decommissioning due to implementing the 2013 Palo Verde decommissioning study. In 2012, the estimate revision includes a change to the probability of extending Four Corners' operating term.

	2013	2012
ARO liability at beginning of year	$ 62,784	$ 56,140
ARO liability at beginning of year	—	—
Liabilities settled	(36)	(450)
Revisions to estimate	(3,401)	1,929
Accretion expense	5,867	5,165
ARO liability at end of year	$ 65,214	$ 62,784

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.

F. 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 expired 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 15,000 options outstanding at December 31, 2012 were exercised during 2013 with a weighted average exercise price of $12.78. The Company received $0.2 million in cash and realized a current tax benefit of $0.1 million. The Company has no stock options outstanding as of December 31, 2013.

The intrinsic value of stock options exercised in 2013 and 2012 were $0.3 million and $0.6 million, respectively. No options were forfeited, vested or expired during 2013 and 2012. No compensation cost was recognized in 2013 and 2012 for 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 2013 and 2012 is presented below (in thousands):

	2013	2012
Expense (a)	$ 2,458	$ 1,508
Deferred tax benefit	860	528
Current tax benefit recognized	109	94

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

The aggregate intrinsic value and fair value at grant date of restricted stock which vested in 2013 and 2012 is presented below (in thousands):

	2013	2012
Aggregated intrinsic value	$ 2,077	$ 2,242
Fair value at grant date	1,765	1,973

The unvested restricted stock transactions for 2013 are presented below:

	Total Shares	Weighted Average Grant Date Fair Value	Unrecognized Compensation Expense (In thousands)	Aggregate Intrinsic Value (In thousands)
Restricted shares outstanding at December 31, 2012	84,446	$ 31.26		
Restricted stock awards	96,279	35.48		
Vested	(58,642)	30.10		
Forfeitures	(1,549)	31.28		
Restricted shares outstanding at December 31, 2013	120,534	35.19	$ 1,976	$ 4,232

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

The weighted average fair value per share at grant date for restricted stock awarded during 2013 and 2012 were:

	2013	2012
Weighted average fair value per share	$ 35.48	$ 32.45

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)	Period Compensation Costs Expensed	Aggregated Intrinsic Value (In thousands)
February 18, 2014	0%	0	$ 954	2011-2013	—
January 29, 2013	150.0%	64,275	849	2010-2012	2,176
January 1, 2012	175.0%	174,038	1,193	2009-2011	6,029
September 3, 2011	112.5%	3,825	40	2008-2011	129
July 9, 2011	112.5%	2,250	23	2008-2011	75

In 2014, 2015 and 2016, 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. The actual number of shares to be issued can range from zero to 181,894 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, 2012	128,033	$ 26.48		
Performance share awards	39,814	34.69		
Performance shares vested	(42,850)	19.82		
Performance shares outstanding at December 31, 2013	124,997	31.38	$ 1,452	$ 4,389

(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 2013 and 2012 is presented below:

	2013	2012
Weighted average per share grant date fair value per share of performance shares awarded	$ 34.69	$ 32.74
Fair value of performance shares vested (in thousands)	849	1,193
Intrinsic value of performance shares vested (in thousands) (a)	1,450	3,464
Compensation expense (in thousands) (b)	1,188	170
Deferred tax benefit related to compensation expense (in thousands)	416	59

(a) Based on a 100% performance level.
(b) Includes adjustments for forfeiture of performance share awards by certain executives.

Repurchase Program

No shares of common stock were repurchased during the twelve months ended December 31, 2013. Detail regarding the Company's stock repurchase program is presented below:

	Since 1999 (a)	Authorized Shares
Shares repurchased (b)	25,406,184	
Cost, including commission (in thousands)	$ 423,647	
Total remaining shares available for repurchase at December 31, 2013		393,816

(a) Represents repurchased shares and cost since inception of the stock repurchase program in 1999.
(b) Shares repurchased does not include 86,735 treasury shares related to employee compensation arrangements outside of the Company's repurchase programs.

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, 2013, the Company paid $10.7 million in quarterly cash dividends to shareholders. The Company paid a total of $42.0 million and $38.9 million in cash dividends during the twelve months ended December 31, 2013 and 2012, respectively. On January 23, 2014, the Board of Directors declared a quarterly cash dividend of $0.265 per share payable on March 31, 2014 to shareholders of record on March 14, 2014.

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

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

	December 31, 2013	December 31, 2012
	(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	$ 37,100
4.50% 2012 Series A refunding bonds, due 2042 (4.63% 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
1.875% 2012 Series A refunding bonds, due 2032 (2.35% 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
3.30% Senior Notes, net of discount, due 2022 (3.43% effective interest rate)	150,000	150,000
Total Account 224	700,000	700,000
Unamortized discount on long-term debt Account 226	(3,515)	(3,600)
Total Long-term Debt	$ 889,620	$ 889,535
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
Obligations Under Capital Lease –Current (Account 243):		
Revolving Credit Facility	$ 16,262	$ 24,064

(1) Pollution Control Bonds ("PCBs")

The Company has four series of tax exempt unsecured PCBs in aggregate principal amount of $193.1 million. The 1.875% 2012 Series A (El Paso Electric Company Four Corners Project) Pollution Control Refunding Revenue Bonds with an aggregate principal amount of $33.3 million are subject to mandatory tender for purchase in September 2017.

(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 N, "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.

The 3.30% senior notes have an aggregate principal amount of $150.0 million and were issued in December 2012. The proceeds, net of a $0.3 million discount, were used to fund construction expenditures and for working capital and general corporate purposes.

(3) RGRT Senior Notes

In 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 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 leases 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 2013.

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

On January 14, 2014, the Company and RGRT entered into a second amended and restated credit agreement related to 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 agreement, the Company has available $300 million and the ability to increase the RCF by up to $100 million (up to a total of $400 million) upon the satisfaction of certain conditions, more fully set forth in the agreement, including obtaining commitments from lenders or third party financial institutions. The RCF has a term ending January 2019. The Company may extend the maturity date up to two times, in each case for an additional one year period upon the satisfaction of certain conditions.

The RCF provides that amounts borrowed by the Company may be used for, among other things, working capital and general corporate purposes. Any amounts borrowed by RGRT may be used, among other things, to finance the acquisition and processing of nuclear fuel. Amounts borrowed by RGRT are guaranteed by the Company and the balance borrowed under the RCF is recorded as a capital lease of nuclear fuel on the regulatory-basis balance sheet. Quarterly lease payments are made based upon units of heat production used by the plant. 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 2013. As of December 31, 2013, the total amount borrowed by RGRT was $16.3 million for nuclear fuel under the RCF. As of December 31, 2013, no borrowings were outstanding under this facility for working capital and general corporate purposes. The weighted average interest rate on the RCF was 1.4% as of December 31, 2013.

As of December 31, 2013, the scheduled maturities for the next five years of long-term debt are as follows (in thousands):

2014	$ —
2015	15,000
2016	—
2017	83,300
2018	—

The $16.3 million outstanding on the RCF for nuclear fuel financing purposes is anticipated to be paid in 2014.

H. Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and liabilities at December 31, 2013 and 2012 are presented below (in thousands):

	December 31,	
	2013	**2012**
Deferred tax assets:		
Plant, principally due to capitalized costs	$ 63,256	$ 60,726
Benefits of federal tax loss carryforwards	17,901	7,470
Pensions and benefits	50,398	76,655
Alternative minimum tax credit carryforward	21,638	21,599
Regulatory liabilities related to income taxes	7,119	7,505
Asset retirement obligation	24,547	22,694
Deferred fuel	—	1,754
Debt related items	7,092	7,236
Other	12,316	18,741
Total gross deferred tax assets	204,267	224,380
Deferred tax liabilities:		
Plant, principally due to depreciation and basis differences	(481,753)	(432,291)
Regulatory assets related to income taxes	(108,362)	(100,796)
Decommissioning	(26,745)	(24,156)
Deferred fuel	(1,990)	—
Other	(8,093)	(7,952)
Total gross deferred tax liabilities	(626,943)	(565,195)
Net accumulated deferred income taxes	$ (422,676)	$ (340,815)

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 2013 and 2012 as follows (in thousands):

	Years Ended December 31, 2013	Years Ended December 31, 2012
Income tax expense:		
Federal:		
Current	$ 1,988	$ 3,512
Deferred	40,813	41,264
Investment tax credit	(703)	(1,158)
Total federal income tax	42,098	43,618
State:		
Current	54	416
Deferred	(414)	697
Total state income tax	$ (360)	$ 1,113

As of December 31, 2013, the Company had $21.6 million of alternative minimum tax ("AMT") credit carryforwards. The AMT credit carryforwards have an unlimited life. As of December 31, 2013, the Company had $17.3 million of federal and $0.4 million of state tax loss carryforwards. If unused, the tax loss carryforwards would expire at the end of 2031 through 2033 and 2016 through 2018, for federal and state, 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, 2013	Years Ended December 31, 2012
Federal income tax expense computed on income at statutory rate	$ 47,081	$ 48,295
Difference due to:		
State income taxes (federal effect)	126	(390)
Investment Tax Credit amortization (net of deferred taxes)	(705)	(753)
Allowance for equity funds used during construction	(2,076)	(1,771)
Amortization of excess deferred taxes	(717)	(717)
Amortization of regulatory assets and liabilities	(379)	(405)
Permanent tax differences	(1,048)	(156)
Other	(184)	(485)
Total federal income tax expense	$ 42,098	$ 43,618

The Company files income tax returns in the United States ("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 2009 and in New Mexico for years prior to 2009. The Company is currently under audit in Texas for tax years 2007 through 2011. A deficiency notice relating to the Company's 1998 through 2003 and 2006 and 2007 income tax returns in Arizona challenges a pollution control credit, a research and development credit and the payroll, sales and property apportionment factors. The Company reached a settlement with Arizona in March 2014 for income tax returns from 1998 through 2007 which did not have a material effect on income tax expense.

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 to 2012 federal income tax returns. In August of 2012, the Company filed a change of accounting method with the IRS, effectively adopting the safe harbor provisions of Rev. Proc 2011-43 related to units of property for capitalized tax assets. The change was included in the 2011 federal income tax return.

The Company recognizes interest and penalties related to tax benefits that are uncertain in interest and penalties accounts. During the years ended December 31, 2013 and 2012, the Company recognized expense of approximately $0.2 million and a benefit of $0.3 million, respectively, in interest. The Company had approximately $0.4 million and $0.1 million for the payment of interest and penalties accrued at December 31, 2013 and December 31, 2012, respectively.

I. 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 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 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 2014	N/A
Power Purchase and Sale Agreement	Freeport	100 MW	January 2015 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 August 2031	August 2011
Power Purchase Agreement	Sun Edison 1	10 MW	June 2012 through June 2037	June 2012
Power Purchase Agreement	Sun Edison 2	12 MW	May 2012 through May 2037	May 2012
Power Purchase Agreement	Hatch Solar Energy Center I, LLC	5 MW	July 2011 through June 2036	July 2011
Power Purchase Agreement	Macho Springs Solar, LLC	50 MW	20 years after operational start date	Expected May 1, 2014
Power Purchase Agreement	Newman Solar, LLC	10 MW	30 years after operational start date	Expected December 31, 2014

The Company has a firm 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 2014. 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 purchased power agreement with Hatch Solar Energy Center I, LLC for a solar photovoltaic project located in southern New Mexico which began commercial operation in July 2011. The Company has 25-year agreements to purchase all of the output of two additional solar photovoltaic projects located in southern New Mexico, SunEdison 1 and SunEdison 2 which achieved commercial operation on June 25, 2012 and May 2, 2012, respectively. The Company entered into these contracts to help meet its renewable portfolio requirements.

In May 2013, the NMPRC approved the Company's agreement with Macho Springs Solar, LLC to purchase the entire generation output delivered from the 50 MW Macho Springs solar photovoltaic project located in Luna County, New Mexico. The term of the purchased power agreement is 20 years from the commercial operation date of the Macho Springs project which is projected to be May 1, 2014. In addition, on September 5, 2013, the Company entered into a purchased power agreement with Newman Solar LLC to purchase, for a term of 30 years, the total output from a solar photovoltaic generation facility of approximately 10 MW that Newman Solar LLC will construct, own and operate on land subleased from the Company in proximity to its Newman Power Station. This solar project is expected to be on line at the end of 2014.

Environmental Matters

General. The Company is subject to extensive laws, regulations and permit requirements with respect to air and greenhouse gas emissions, water discharges, soil and water quality, waste management and disposal, natural resources and other environmental matters by federal, state, regional, tribal and local authorities. Failure to comply with such laws, regulations and requirements can result in actions by authorities or other third parties 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, regulations and requirements are subject to change through modification or reinterpretation, or the introduction of new laws and regulations and, as a result, 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"), associated regulations and comparable state and local laws and regulations relating to air emissions impose, among other obligations, limitations on pollutants generated during the Company's operations, including sulfur dioxide ("SO2"), particulate matter ("PM"), nitrogen oxides ("NOx") and mercury.

Clean Air Interstate Rule/Cross State Air Pollution Rule. The EPA Clean Air Interstate Rule ("CAIR"), as applied to the Company since 2009, involves requirements to limit emissions of NOx and SO2 from certain of the Company's power plants in Texas and/or purchase allowances representing other parties' emissions reductions. While the U.S. Court of Appeals for the District of Columbia Circuit voided CAIR in 2008, on appeal the rule was reinstated until such time as the EPA promulgates a replacement rule. Because the appellate court in August 2012 also vacated the EPA's proposed replacement, which is called the Cross-State Air Pollution Rule ("CSAPR"), CAIR remains in effect. On March 29, 2013, the U.S. Solicitor General petitioned the U.S. Supreme Court to review the D.C. Circuit's decision to vacate CSAPR. On June 24, 2013, the Supreme Court agreed to hear the case, and oral arguments were heard on December 10, 2013. The timing and outcome of the Supreme Court decision is unknown, and in the meantime, the Company remains subject to CAIR.

National Ambient Air Quality Standards. Under the CAA, the EPA sets National Ambient Air Quality Standards ("NAAQS") for six criteria pollutants considered harmful to public health and the environment, including PM, NOx, carbon monoxide ("CO"), ozone and SO2. NAAQS must be reviewed by the EPA at five-year intervals. In 2010, the EPA tightened the NAAQS for both NOx and SO2. In December 2012, the EPA tightened the NAAQS for fine PM, and it is expected to propose more stringent ozone NAAQS in 2014 (with a final rule in 2015). The Company continues to evaluate what impact these final and proposed NAAQS 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 financial results.

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 oil-and coal-fired power plants, which requires significant reductions in emissions of mercury and other air toxics. Several judicial and other challenges are being made to this rule. These challenges notwithstanding, companies impacted by the new standards will generally have up to three years to comply. Information from the Four Corners plant operator, APS, indicates that APS currently believes Units 4 and 5 will require no additional modifications to achieve compliance with the Utility MACT standards.

Other Laws and Regulations and Risks. As stated above, the Company intends to cease its participation in Four Corners at the expiration of the 50-year participation agreement in 2016. The Company believes that it has better economic and cleaner alternatives for serving the energy needs of its customers than coal-fired generation, which is subject to extensive regulation and litigation. For example, as a result of APS's recent Best Available Retrofit Technology Federal Implementation Plan compliance strategy notification to the EPA, Four Corners is required to install expensive pollution control equipment in order to continue operation in the future. The Company's share of the cost of these controls is currently estimated by APS to be approximately $39 million if the Company were to extend its participation in the plant. In addition, the EPA has entered into a consent decree which would require it to sign for publication a final action regarding the regulation of coal combustion residuals ("CCR") under the federal Resource, Conservation and Recovery Act by December 19, 2014. Once issued, the Company may be required to incur significant costs to address CCRs either generated in the past and disposed of at or from Four Corners, as well as CCRs generated in connection with the ongoing operations of Four Corners. Further, assured supplies of water are important for the Company's operations and assets, including Four Corners. Four Corners is located in a region that has been experiencing drought conditions which could affect the plant's water supply. Four Corners has accordingly been involved in negotiations and proceedings with third parties relating to water supply issues. The drought conditions and related negotiations and proceedings could adversely affect the amount of power available, or the price thereof, from Four Corners.

Climate Change. The U.S. federal government has either considered, proposed and/or finalized legislation or regulations limiting GHG emissions, including carbon dioxide. In particular, the U.S. Congress periodically considers legislation to restrict or regulate GHG emissions. In the past few years, the EPA began using the CAA to regulate carbon dioxide and other GHG emissions, such as the 2009 GHG Reporting Rule and the EPA's sulfur hexafluoride ("SF6") reporting rule, both of which applied to the Company, as well as the EPA's 2010 actions to impose permitting requirements on new and modified sources of GHG emissions, which may create significant costs for power plant owners and operators. On June 25, 2013, President Obama set forth his plan to address climate change. He reiterated a goal of reducing GHG "in the range of 17 percent" below 2005 levels by 2020. The plan included a variety of executive actions, including future regulatory measures to reduce carbon emissions from power plants. In a White House memorandum of the same date, the President directed the EPA to issue a new proposal for GHG rulemaking addressing new power plants by September 20, 2013, and a rule for existing power plants by June 1, 2014. The formal proposal for new power plants was published in the Federal Register on January 8, 2014. The Company continues its review of the new proposal and plans to participate in the post-publication comment period (with extension) ending May 9, 2014. Given the very significant remaining uncertainties regarding these rules, the Company believes it is impossible to meaningfully quantify the costs of these potential requirements at present.

In addition, almost half the U.S. states, either individually and/or through multi-state regional initiatives, have begun to consider how to address GHG emissions and have developed, or are actively considering the development of emission inventories or regional GHG cap and trade programs. While 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 emissions are low relative to electric power companies who rely more on coal-fired generation, current and future legislation and regulation of GHGs or any future related litigation could impose significant costs and/or operating restrictions on the Company, reduced demand for the power the Company generates and/or require the Company to purchase rights to emit GHGs, any of which could be material to 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 results of 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. 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 to meaningfully quantify the costs of these potential impacts at present.

Environmental Litigation and Investigations. Since 2009, the EPA and certain environmental organizations have been scrutinizing, and in some cases, have filed lawsuits, relating to certain air emissions and air permitting matters related to Four Corners. In particular, since July 2011, the U.S. Department of Justice (the "DOJ"), on behalf of the EPA, and APS have been engaged in substantive settlement negotiations in an effort to resolve certain of the pending matters. The allegations being addressed through settlement negotiations are that APS failed to obtain the necessary permits and install the controls necessary under the CAA to reduce SO2, NOx, and PM, and that defendants failed to obtain an operating permit under Title V of the CAA that reflects applicable requirements imposed by law. In March 2012, the DOJ provided APS with a draft consent decree to settle the EPA matter, which decree contains specific provisions for the reduction and control of NOx, SO2, and PM, as well as provisions for a civil penalty, and expenditures on environmental mitigation projects with an emphasis on projects that address alleged harm to the Navajo Nation. Settlement discussions are on-going and the Company is unable to predict the outcome of these settlement negotiations. The Company has accrued a total of $0.5 million as a loss contingency related to this matter.

The Company received notice 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 ("PSD") provisions of the CAA related to Four Corners. On January 6, 2012, Earthjustice filed a First Amended Complaint adding claims for violations of the CAA's New Source Performance Standards ("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 referenced NSPS program. The plaintiffs further request the court to order the payment of civil penalties, including a beneficial mitigation project. On April 2, 2012, APS and the other Four Corners' participants filed motions to dismiss with the court. The case is being held in abeyance while the parties seek to negotiate a settlement. On March 30, 2013, upon joint motion of the parties, the court issued an order deeming the motions to dismiss withdrawn without prejudice during pendency of the stay. At such time as the stay is lifted, APS, the Company and the other Four Corners participants may reinstate the motions to dismiss. Most recently, on March 17, 2014, the parties filed a joint motion to extend the stay in the case by 30 days. On March 18, 2014, the Court granted the motion holding the matter in abeyance until April 15, 2014. The parties are in discussions concerning whether to jointly file a motion to extend the stay until May 1, 2014. The Company is unable to predict the outcome of this litigation.

New Mexico Tax Matter Related to Coal Supplied to Four Corners

On May 23, 2013, the New Mexico Taxation and Revenue Department issued a notice of assessment for coal severance surtax, penalty, and interest totaling approximately $30 million related to coal supplied under the coal supply agreement for Four Corners (the "Assessment"). The Company's share of the Assessment is approximately $1.5 million. On behalf of the Four Corners participants, the coal supplier made a partial payment of the Assessment and immediately filed a refund claim with respect to that partial payment in August 2013. The New Mexico Taxation and Revenue Department denied the refund claim. On December 19, 2013, the coal supplier and APS, on its own behalf and as operating agent for Four Corners, filed complaints with the New Mexico

District Court contesting both the validity of the Assessment and the refund claim denial. APS believes the Assessment and the refund claim denial are without merit. The Company cannot predict the timing, results, or potential impacts of the outcome of this litigation.

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 2015. The Company also has several other leases for office, parking facilities and equipment which expire within the next four 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's total annual rental expense related to operating leases was $1.2 million and $1.3 million for 2013 and 2012, respectively. As of December 31, 2013, the Company's minimum future rental payments for the next five years are as follows (in thousands):

2014	$	1,081
2015		1,028
2016		600
2017		442
2018		408

Union Matters

The Company has approximately 1,000 employees, about 40% of whom are covered by a collective bargaining agreement. The International Brotherhood of Electrical Workers Local 960 ("Local 960") represents the Company's employees working primarily in the power plants, substations, line crews, meter reading and collection, facilities services, and customer service. The Company entered into a new collective bargaining agreement effective September 3, 2013, with Local 960 for a three-year term ending September 2, 2016. The agreement provides for pay increases of 3% on September 3, 2013, 3% on September 3, 2014 and 2.25% on September 3, 2015.

J. 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, the Company 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 B and Note I for discussion of the effects of government legislation and regulation on the Company.

K. 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. Retirement benefits are based on the employee's final average pay and years of service. 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 primarily invested in common collective trusts which hold equity securities, debt securities and cash equivalents and are managed by a professional investment manager 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,			
	2013		2012	
	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	$ 320,846	$ 27,241	$ 296,293	$ 26,547
Service cost	9,137	190	8,530	299
Interest cost	12,742	872	12,594	963
Actuarial (gain) loss	(15,373)	(533)	12,417	1,338
Benefits paid	(9,537)	(1,872)	(8,988)	(1,906)
Benefit obligation at end of year	317,815	25,898	320,846	27,241
Change in plan assets:				
Fair value of plan assets at end of prior year	220,568	—	191,369	—
Actual return on plan assets	31,800	—	20,187	—
Employer contribution	15,000	1,872	18,000	1,906
Benefits paid	(9,537)	(1,872)	(8,988)	(1,906)
Fair value of plan assets at end of year	257,831	—	220,568	—
Funded status at end of year	$ (59,984)	$ (25,898)	$ (100,278)	$ (27,241)

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

	December 31,			
	2013		2012	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Current liabilities	$ —	$ (1,870)	$ —	$ (1,829)
Noncurrent liabilities	(59,984)	(24,028)	(100,278)	(25,412)
Total	$ (59,984)	$ (25,898)	$ (100,278)	$ (27,241)

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

	December 31,			
	2013		2012	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Projected benefit obligation	$ (317,815)	$ (25,898)	$ (320,846)	$ (27,241)
Accumulated benefit obligation	(275,555)	(25,077)	(274,890)	(26,363)
Fair value of plan assets	257,831	—	220,568	—

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

	Years Ended December 31,			
	2013		2012	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 85,261	$ 8,508	$ 125,763	$ 9,701
Prior service cost	—	219	3	314
Total	$ 85,261	$ 8,727	$ 125,766	$ 10,015

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

	December 31,					
	2013			2012		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan
Discount rate	4.9%	3.9%	4.9%	4.0%	3.1%	4.0%
Rate of compensation increase	4.75%	N/A	4.75%	4.75%	N/A	4.75%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is reviewed at each measurement date. The discount rate used to measure obligations is based on a spot rate yield curve that matches projected future payments with the appropriate interest rate applicable to the timing of the projected future benefit payments. A 1% increase in the discount rate would decrease the December 31, 2013 retirement plans' projected benefit obligation by 12.5%. A 1% decrease in the discount rate would increase the December 31, 2013 retirement plans' projected benefit obligation by 15.5%.

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

	Years Ended December 31,			
	2013		2012	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Service cost	$ 9,137	$ 190	$ 8,530	$ 299
Interest cost	12,742	872	12,594	963
Expected return on plan assets	(17,108)	—	(14,443)	—
Amortization of:				
Net loss	10,437	661	10,729	627
Prior service cost	3	94	21	94
Net periodic benefit cost	$ 15,211	$ 1,817	$ 17,431	$ 1,983

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

	Years Ended December 31,			
	2013		2012	
	Retirement Income Plan	Non-Qualified Retirement Plans	Retirement Income Plan	Non-Qualified Retirement Plans
Net (gain) loss	$ (30,065)	$ (533)	$ 6,672	$ 1,337
Amortization of:				
Net loss	(10,437)	(661)	(10,729)	(627)
Prior service cost	(3)	(94)	(21)	(94)
Total recognized in other comprehensive income	$ (40,505)	$ (1,288)	$ (4,078)	$ 616

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

	Years Ended December 31,			
	2013		2012	
	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	$ (25,294)	$ 529	$ 13,353	$ 2,599

The following are amounts in accumulated other comprehensive income that are expected to be recognized as components of net periodic benefit cost during 2014 (in thousands):

	Retirement Income Plan	Non-Qualified Retirement Plans
Net loss	$ 6,270	$ 570
Prior service cost	—	90

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

	2013			2012		
		Non-Qualified			Non-Qualified	
	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan	Retirement Income Plan	Supplemental Retirement Plan	Excess Benefit Plan
Discount rate	4.0%	3.1%	4.0%	4.3%	3.6%	4.1%
Expected long-term return on plan assets	7.5%	N/A	N/A	7.5%	N/A	N/A
Rate of compensation increase	4.75%	N/A	4.75%	5.0%	N/A	5.0%

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is reviewed at each measurement date. The discount rate used to measure net periodic benefit cost is based on a spot rate yield curve that matches projected future payments with the appropriate interest rate applicable to the timing of the projected future benefit payments.

The Company's overall expected long-term rate of return on assets is 7.5% effective January 1, 2013, 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, 2013
Equity securities	55%
Fixed income	40%
Alternative investments	5%
Total	100%

The Retirement Plan invests the majority of its plan assets in common collective trusts which includes a diversified portfolio of domestic and international equity securities and fixed income securities. The Retirement Plan fund also invests in a real estate limited partnership. The expected rates of return for the funds are assessed annually and are based on long-term relationships among major asset classes and the level of incremental returns that can be earned by the successful implementation of different active investment management strategies. Equity returns are based on estimates of long-term inflation rate, real rate of return, 10-year Treasury bond premium over cash and equity risk premium. Fixed income returns are based on maturity, long-term inflation, real rate of return and credit spreads.

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 or securities held in the mutual funds and underlying portfolios of the Retirement Plan are primarily obtained from independent pricing services. These prices are based on observable market data.

- 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. The Common Collective Trusts are valued using the net asset value ("NAV") provided by the administrator of the fund. The NAV price is quoted on a restrictive market although the underlying investments are traded on active markets.

- 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 NAV of the investment.

During 2013, the Company sold the majority of its assets held in active markets, classified as Level 1, and invested these assets in common collective trusts which are classified as Level 2. The fair value of the Company's Retirement Plan assets at December 31, 2013 and 2012, 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, 2013**	**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	$ 940	$ 940	$ —	$ —
Guaranteed Investment Contract	1,126	—	1,126	—
Common Collective Trusts (a)				
Equity funds	142,960	—	142,960	—
Fixed income funds	103,948	—	103,948	—
Total Common Collective Trusts	246,908	—	246,908	—
Limited Partnership Interest in Real Estate (b)	8,857	—	—	8,857
Total Plan Investments	$ 257,831	$ 940	$ 248,034	$ 8,857

Description of Securities	Fair Value as of December 31, 2012	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	$ 9,163	$ 9,163	$ —	$ —
U.S. Treasury Securities	24,854	24,854	—	—
Guaranteed Investment Contract	1,059	—	1,059	—
Common Stock	52,149	52,149	—	—
Mutual Funds - Fixed Income	59,150	59,150	—	—
Mutual Funds – Equity	65,634	65,634	—	—
Limited Partnership Interest in Real Estate (b)	8,559	—	—	8,559
Total Plan Investments	$ 220,568	$ 210,950	$ 1,059	$ 8,559

(a) The Common Collective Trusts are invested in equity or fixed income securities, or a combination thereof. The investment objective of each trust is to produce returns in excess of, or commensurate with, its predefined index.

(b) 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 on investment is realized as land is sold. The fair value of the limited partnership interest in real estate is based on the NAV 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
Balances at December 31, 2011	$ 8,511
Unrealized gain in fair value	48
Balances at December 31, 2012	8,559
Unrealized gain in fair value	298
Balances at December 31, 2013	$ 8,857

There were no transfers in or out of Level 1 and Level 2 fair value measurements categories due to changes in observable inputs during the twelve month periods ending December 31, 2013 and 2012. There were no purchases, sales, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2013 and 2012.

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 manager has 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 $13.9 million to its retirement plans in 2014.

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
2014	$ 10,902	$ 1,870
2015	12,015	1,818
2016	13,180	1,772
2017	14,440	1,829
2018	15,807	1,715
2019-2023	96,510	9,447

In 2014, the Company implemented a redesigned Retirement Income Plan and Excess Benefit Plan. Effective April 1, 2014, the Company offered a cash balance pension plan as an alternative to its current final average pay pension plan for employees hired prior to January 1, 2014. The cash balance pension plan also included an enhanced employer matching contribution to the employee's respective 401(k) Defined Contribution Plan (discussed below). For employees who elected the new cash balance pension plan, the pension benefit earned under the existing final average pay pension plan was frozen as of March 31, 2014. Employees hired after January 1, 2014 will be automatically enrolled in the cash balance pension plan. The Company remeasured the assets and liabilities of the retirement plans during the first quarter of 2014.

401(k) Defined Contribution Plans

The Company sponsors 401(k) defined contribution plans covering substantially all employees. Annual matching contributions made to the savings plans for the years 2013 and 2012 were $1.9 million and $1.8 million, respectively. 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. Effective April 1, 2014, for employees enrolled in the cash balance pension plan (discussed above), the Company will provide a 100 percent matching contribution up to 6 percent of the employee's compensation subject to certain other limits and exclusions.

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 no more than the IRS tax deductible limit, as actuarially calculated. The assets of the plan are primarily invested in common collective trusts which hold equity securities, debt securities, and cash equivalents and are managed by a professional investment manager 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 plan (in thousands):

	December 31, 2013	December 31, 2012
Change in benefit obligation:		
Benefit obligation at end of prior year	$ 135,680	$ 133,272
Service cost	3,843	4,378
Interest cost	5,156	5,651
Actuarial gain	(48,778)	(5,009)
Amendment (a)	(97)	—
Benefits paid	(4,013)	(3,929)
Retiree contributions	1,056	1,086
Medicare Part D subsidy	—	231
Benefit obligation at end of year	92,847	135,680
Change in plan assets:		
Fair value of plan assets at end of prior year	36,510	32,817
Actual return on plan assets	5,539	2,605
Employer contribution	3,100	3,700
Benefits paid	(4,013)	(3,929)
Retiree contributions	1,056	1,086
Medicare Part D subsidy	—	231
Fair value of plan assets at end of year	42,192	36,510
Funded status (b)	$ (50,655)	$ (99,170)

(a) Amendment relates to modification of the Company's Other Postretirement Benefit Plan which limits the Company's premium contribution. The amendment became effective October 3, 2013 and resulted in a remeasurement of the plan.

(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, 2013	December 31, 2012
Net (gain) loss	$ (38,110)	$ 13,630
Prior service credit	(19,210)	(24,770)
	$ (57,320)	$ (11,140)

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

	December 31, 2013	December 31, 2012
Discount rate at end of year	4.90%	4.10%
Health care cost trend rates:		
Initial	7.50%	7.75%
Ultimate	4.50%	4.50%
Year ultimate reached	2026	2026

The discount rate is reviewed at each measurement date. The discount rate used to measure obligations is based on a spot rate yield curve that matches projected future payments with the appropriate interest rate applicable to the timing of the projected future benefit payments. A 1% increase in the discount rate would decrease the December 31, 2013 accumulated postretirement benefit obligation by 12.8%. A 1% decrease in the discount rate would increase the December 31, 2013 accumulated postretirement benefit obligation by 16.1%.

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

	Years Ended December 31,	
	2013	2012
Service cost	$ 3,843	$ 4,378
Interest cost	5,156	5,651
Expected return on plan assets	(1,951)	(1,714)
Amortization of:		
Unrecognized transition obligation	—	2,426
Prior service benefit	(5,657)	(5,877)
Net (gain) loss	(626)	615
Net periodic benefit cost	$ 765	$ 5,479

The net periodic benefit cost includes amortization of unrecognized transition obligation over a twenty-year period which ended in 2012. The changes in benefit obligations recognized in other comprehensive income are presented below (in thousands):

	Years Ended December 31,	
	2013	2012
Net gain	$ (52,366)	$ (5,900)
Prior service benefit	(97)	—
Amortization of:		
Unrecognized transition obligation	—	(2,426)
Prior service benefit	5,657	5,877
Net gain (loss)	626	(615)
Total recognized in other comprehensive income	$ (46,180)	$ (3,064)

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

	Years Ended December 31,	
	2013	2012
Total recognized in net periodic benefit cost and other comprehensive income	$ (45,415)	$ 2,415

The amount in accumulated other comprehensive income that is expected to be recognized as a component of net periodic benefit cost during 2014 is a prior service benefit of $4.8 million and a net gain of $2.6 million.

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

	2013 (a)	2012
Discount rate at beginning of year	4.1%	4.3%
Expected long-term return on plan assets	5.2%	5.2%
Health care cost trend rates:		
Initial	7.75%	8.0%
Ultimate	4.5%	4.5%
Year ultimate reached	2026	2026

(a) The Other Postretirement Benefits Plan was remeasured at October 3, 2013 due to a plan amendment. The discount rate increased from 4.1% as of January 1, 2013 to 4.9% at the remeasurement date. All other assumptions remained consistent with assumptions used at January 1, 2013.

The Company reassesses various actuarial assumptions at least on an annual basis. The discount rate is reviewed at each measurement date. The discount rate used to measure net periodic benefit cost is based on a spot yield curve that matches projected future payments with the appropriate interest rate applicable to the timing of the projected future benefit payments.

For measurement purposes, a 7.75% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2013. The rate was assumed to decrease gradually to 4.5% for 2026 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, 2013 benefit obligation by $14.3 million or $10.8 million, respectively. In addition, a 1% change in said rate would increase or decrease the aggregate 2013 service and interest cost components of the net periodic benefit cost by $2.1 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, 2013. 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, 2013
Equity securities	65%
Fixed income	30%
Alternative investments	5%
Total	100%

The Other Postretirement Benefit Plan invests the majority of its plan assets in common collective trusts which includes a diversified portfolio of domestic and international equity securities and fixed income securities. The asset portfolio also includes cash equivalents and a real estate limited partnership. The expected rate of returns for the funds are assessed annually and are based on long-term relationships among major asset classes and the level of incremental returns that can be earned by the successful implementation of different active investment management strategies. Equity returns are based on estimates of long-term inflation rate, real rate of return, 10-year Treasury bond premium over cash and equity risk premium. Fixed income returns are based on maturity, long-term inflation, real rate of return and credit spreads.

FASB guidance on disclosure for other postretirement benefit 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 or securities held in the mutual funds and underlying portfolios of the Other Postretirement Benefits Plan are primarily obtained from independent pricing services. These prices are based on observable market data.

- 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. The Common Collective Trusts are valued using the NAV provided by the administrator of the fund. The NAV price is quoted on a restrictive market although the underlying investments are traded on active markets.

- 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 NAV of the investment.

During 2013, the Company sold the majority of its assets held in active markets, classified as Level 1, and invested these assets in common collective trusts which are classified as Level 2. The fair value of the Company's Other Postretirement Benefits Plan assets at December 31, 2013 and 2012, 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, 2013**	**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	$ 33	$ 33	$ —	$ —
Common Collective Trusts (a)				
Equity funds	28,077	—	28,077	—
Fixed income funds	12,421	—	12,421	—
Total Common Collective Trusts	40,498	—	40,498	—
Limited Partnership Interest in Real Estate (b)	1,661	—	—	1,661
Total Plan Investments	$ 42,192	$ 33	$ 40,498	$ 1,661

Description of Securities	**Fair Value as of December 31, 2012**	**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	$ 2,075	$ 2,075	$ —	$ —
Municipal Securities – Tax Exempt	12,811	—	12,811	—
Common Stock	14,397	14,397	—	—
Mutual Funds – Equity	5,622	5,622	—	—
Limited Partnership Interest in Real Estate (b)	1,605	—	—	1,605
Total Plan Investments	$ 36,510	$ 22,094	$ 12,811	$ 1,605

(a) The Common Collective Trusts are invested in equity or fixed income securities, or a combination thereof. The investment objective of each trust is to produce returns in excess of, or commensurate with, its predefined index.

(b) 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 NAV 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, 2011	$ 1,596
Unrealized gain in fair value	9
Balance at December 31, 2012	1,605
Unrealized gain in fair value	56
Balance at December 31, 2013	$ 1,661

There were no transfers in or out of Level 1 and Level 2 fair value measurements categories due to changes in observable inputs during the twelve month periods ending December 31, 2013 and 2012. There were no purchases, sales, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2013 and 2012.

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 manager has 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 does not expect to contribute to its other postretirement benefits plan in 2014. The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid (in thousands):

2014	$ 3,024
2015	3,414
2016	3,810
2017	4,230
2018	4,639
2019-2023	28,238

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 named 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. In 2013, the Company reached the required levels of earnings per share, safety, regulatory compliance, and customer satisfaction goals for an incentive payment of $4.0 million. The Company reached the required levels of earnings per share, safety, regulatory compliance, and customer satisfaction goals for an incentive payment of $7.9 million in 2012. The Company has renewed the Incentive Plan in 2014 with similar goals.

L. 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 on April 30, 2009.

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

City	Period	Franchise Fee (a)
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) 0.75% of the El Paso franchise fee is to be placed in a restricted fund to be used solely for economic development and renewable energy purposes.

Military Installations

The Company serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and Fort Bliss. The military installations represent approximately 5% of the Company's annual retail revenues. Fort Bliss takes retail electric service from the Company under the applicable Texas tariffs. 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.

M. 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,			
	2013		2012	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Pollution Control Bonds	$ 193,135	$ 193,990	$ 193,135	$ 215,228
Senior Notes	696,485	734,515	696,400	823,497
RGRT Senior Notes (1)	110,000	115,850	110,000	120,985
RCF (1)	16,262	16,262	24,064	24,064
Total	$ 1,015,882	$ 1,060,617	$ 1,023,599	$ 1,183,774

(1) Nuclear fuel capital lease obligations as of December 31, 2013 and December 31, 2012 is funded through the $110 million RGRT Senior Notes and $16.3 million and $24.1 million, respectively under the RCF. As of December 31, 2013 and 2012, no amount was outstanding under the RCF for working capital or general corporate purposes. The interest rate on the Company's borrowings under the RCF is reset throughout the period 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 2014, 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, 2013, 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, 2013, 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 $214.1 million and $187.1 million at December 31, 2013 and 2012, 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, 2013					
	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	$ 6,444	$ (169)	$ 1,421	$ (119)	$ 7,865	$ (288)
U.S. Government Bonds	8,114	(245)	10,866	(840)	18,980	(1,085)
Municipal Obligations	12,286	(335)	7,782	(479)	20,068	(814)
Corporate Obligations	3,284	(96)	901	(54)	4,185	(150)
Total Debt Securities	30,128	(845)	20,970	(1,492)	51,098	(2,337)
Common Stock	2,305	(126)	—	—	2,305	(126)
Total Temporarily Impaired Securities	$ 32,433	$ (971)	$ 20,970	$ (1,492)	$ 53,403	$ (2,463)

(1) Includes approximately 122 securities.

	December 31, 2012					
	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	$ 1,792	$ (5)	$ 416	$ (9)	$ 2,208	$ (14)
U.S. Government Bonds	6,633	(79)	4,457	(114)	11,090	(193)
Municipal Obligations	5,306	(39)	5,760	(241)	11,066	(280)
Corporate Obligations	452	(11)	—	—	452	(11)
Total Debt Securities	14,183	(134)	10,633	(364)	24,816	(498)
Common stock	3,603	(409)	—	—	3,603	(409)
Total Temporarily Impaired Securities	$ 17,786	$ (543)	$ 10,633	$ (364)	$ 28,419	$ (907)

(2) Includes approximately 65 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 does not anticipate expending 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, 2013		December 31, 2012	
	Fair Value	Unrealized Gains	Fair Value	Unrealized Gains
Description of Securities:				
Federal Agency Mortgage Backed Securities	$ 9,929	$ 433	$ 17,289	$ 1,036
U.S. Government Bonds	6,258	126	13,295	678
Municipal Obligations	8,783	450	22,797	1,531
Corporate Obligations	9,188	506	12,378	1,134
Total Debt Securities	34,158	1,515	65,759	4,379
Common Stock	103,808	43,145	73,210	22,839
Equity Mutual Funds	16,802	3,081	15,194	1,821
Cash and Cash Equivalents	5,924	—	4,471	—
Total	$ 160,692	$ 47,741	$ 158,634	$ 29,039

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 ten years or more. The mortgage-backed securities have an estimated weighted average maturity which generally range from three years to eight years and reflects anticipated future prepayments. The contractual year for maturity for these available-for-sale securities as of December 31, 2013 is as follows (in thousands):

	Total	2014	2015 through 2018	2019 through 2023	2024 and Beyond
Municipal Debt Obligations	$ 28,851	$ 1,486	$ 13,311	$ 10,920	$ 3,134
Corporate Debt Obligations	13,373	321	3,711	5,525	3,816
U.S. Government Bonds	25,238	1,216	14,149	7,217	2,656

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, 2013 and 2012 the Company recognized other than temporary impairment losses on its available-for-sale securities as follows (in thousands):

	2013	2012
Unrealized holding losses included in pre-tax income	$ —	$ (479)

The Company's marketable securities in its decommissioning trust funds are sold from time to time and the Company uses the specific identification basis 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, 2013 and 2012 and the related effects on pre-tax income are as follows (in thousands):

	2013	2012
Proceeds from sales or maturities of available-for-sale securities	$ 56,148	$ 98,542
Gross realized gains included in pre-tax income	$ 986	$ 1,478
Gross realized losses included in pre-tax income	(433)	(2,041)
Gross unrealized losses included in pre-tax income	—	(479)
Net gains (losses) in pre-tax income	$ 553	$ (1,042)
Net unrealized holding gains included in accumulated other comprehensive income	$ 17,699	$ 9,927
Net (gains) losses reclassified out of accumulated other comprehensive income	(553)	1,042
Net gains in other comprehensive income	$ 17,146	$ 10,969

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. 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, mutual funds 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, 2013 and 2012, 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, 2013	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	$ 1,555	$ —	$ —	$ 1,555
Available for sale:				
U.S. Government Bonds	$ 25,238	$ 25,238	$ —	$ —
Federal Agency Mortgage Backed Securities	17,794	—	17,794	—
Municipal Obligations	28,851	—	28,851	—
Corporate Obligations	13,373	—	13,373	—
Subtotal, Debt Securities	85,256	25,238	60,018	—
Common Stock	106,113	106,113	—	—
Equity Mutual Funds	16,802	16,802	—	—
Cash and Cash Equivalents	5,924	5,924	—	—
Total available for sale	$ 214,095	$ 154,077	$ 60,018	$ —

Description of Securities	Fair Value as of December 31, 2012	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	$ 1,295	$ —	$ —	$ 1,295
Available for sale:				
U.S. Government Bonds	$ 24,385	$ 24,385	$ —	$ —
Federal Agency Mortgage Backed Securities	19,497	—	19,497	—
Municipal Obligations	33,863	—	33,863	—
Corporate Obligations	12,830	—	12,830	—
Subtotal, Debt Securities	90,575	24,385	66,190	—
Common Stock	76,813	76,813	—	—
Equity Mutual Funds	15,194	15,194	—	—
Cash and Cash Equivalents	4,471	4,471	—	—
Total available for sale	$ 187,053	$ 120,863	$ 66,190	$ —

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

	2013	2012
Balance at January 1	$ 1,295	$ 1,120
Net unrealized gains in fair value recognized in income (a)	260	175
Balance at December 31	$ 1,555	$ 1,295

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

There were no transfers in or out of Level 1 and Level 2 fair value measurements categories due to changes in observable inputs during the twelve month periods ending December 31, 2013 and 2012. There were no purchases, sales, issuances, and settlements related to the assets in the Level 3 fair value measurement category during the twelve month periods ending December 31, 2013 and 2012.

N. Supplemental Statements of Cash Flows Disclosures

	Years Ended December 31,	
	2013	2012
	(In thousands)	
Cash paid (received) for:		
Interest on long-term debt and borrowing under the revolving credit facility	$ 53,752	$ 50,189
Income taxes paid (refund), net	244	5,031
Non-cash financing activities:		
Grants of restricted shares of common stock	3,224	2,411
Issuance of performance shares	849	1,193

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	/ /	End of 2013/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	13,660,747			(79,853,886)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	810,348			5,475,520
3	Preceding Quarter/Year to Date Changes in Fair Value	7,720,913			(1,356,810)
4	Total (lines 2 and 3)	8,531,261			4,118,710
5	Balance of Account 219 at End of Preceding Quarter/Year	22,192,008			(75,735,176)
6	Balance of Account 219 at Beginning of Current Year	22,192,008			(75,735,176)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(435,665)			3,037,622
8	Current Quarter/Year to Date Changes in Fair Value	14,481,526			51,369,555
9	Total (lines 7 and 8)	14,045,861			54,407,177
10	Balance of Account 219 at End of Current Quarter/Year	36,237,869			(21,327,999)

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		(12,795,453)	(78,988,592)		
2		254,619	6,540,487		
3			6,364,103		
4		254,619	12,904,590	93,220,300	106,124,890
5		(12,540,834)	(66,084,002)		
6		(12,540,834)	(66,084,002)		
7		242,697	2,844,654		
8			65,851,081		
9		242,697	68,695,735	92,779,951	161,475,686
10		(12,298,137)	2,611,733		

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

The Company's decommissioning trust funds include marketable securities which are reported at fair value. These securities are classified as available for sale under FASB guidance for certain investments in debt and equity securites and are valued using prices and other relevant information generated by market transactions involving identical or comparable securities.

Schedule Page: 122(a)(b) Line No.: 1 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 component of net periodic benefit cost of the period.

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.

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	/ /	End of 2013/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)	3,671,007,122	3,671,007,122
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified	266,839,775	266,839,775
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,937,846,897	3,937,846,897
9	Leased to Others		
10	Held for Future Use		
11	Construction Work in Progress	282,646,861	282,646,861
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,220,493,758	4,220,493,758
14	Accum Prov for Depr, Amort, & Depl	2,069,281,349	2,069,281,349
15	Net Utility Plant (13 less 14)	2,151,212,409	2,151,212,409
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,032,293,724	2,032,293,724
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	36,987,625	36,987,625
22	Total In Service (18 thru 21)	2,069,281,349	2,069,281,349
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)	2,069,281,349	2,069,281,349

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	/ /	End of 2013/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
					3
					4
					5
					6
					7
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					10
					11
					12
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					14
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					31
					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	/ /	End of 2013/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)	191,084,821	32,579,707
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	69,700,908	-2,292,091
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	121,383,913	
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)		

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
	34,274,623	189,389,905	12
-41,475,872	34,274,623	74,610,066	13
		114,779,839	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 2013 reloads in Units 1 and 3.

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

Dry cask storage costs allocated to Units 2 and 3.

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

Retirement of fully amortized nuclear fuel in connection with the 2013 reloads in Units 1 and 3.

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 borrowings under a 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, 2013 was $126.3 million of which $16.3 million had been borrowed under the revolving credit facility, and $110 million was borrowed through the senior notes. During 2013, the Company capitalized approximately $5.6 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	/ /	End of 2013/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	103,248,487	15,314,417
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	103,248,487	15,314,417
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	291,469	
9	(311) Structures and Improvements	41,684,157	2,359,214
10	(312) Boiler Plant Equipment	221,890,663	5,150,699
11	(313) Engines and Engine-Driven Generators	54,433,022	3,939,355
12	(314) Turbogenerator Units	130,911,273	1,599,854
13	(315) Accessory Electric Equipment	36,125,853	60,829
14	(316) Misc. Power Plant Equipment	57,657,619	923,369
15	(317) Asset Retirement Costs for Steam Production	1,712,310	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	544,706,366	14,033,320
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,347,703	
19	(321) Structures and Improvements	472,000,467	16,339,757
20	(322) Reactor Plant Equipment	743,057,197	5,071,643
21	(323) Turbogenerator Units	228,706,814	5,102,168
22	(324) Accessory Electric Equipment	171,018,968	1,079,684
23	(325) Misc. Power Plant Equipment	89,010,058	388,608
24	(326) Asset Retirement Costs for Nuclear Production	-40,328,558	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,665,812,649	27,981,860
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	771,251	62,531
39	(342) Fuel Holders, Products, and Accessories	480,893	4,135,212
40	(343) Prime Movers		80,327,287
41	(344) Generators	12,287,312	136,652
42	(345) Accessory Electric Equipment	618,778	9,750,977
43	(346) Misc. Power Plant Equipment	4,033,083	446,483
44	(347) Asset Retirement Costs for Other Production	15,479	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	18,216,796	94,859,142
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,228,735,811	136,874,322

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
1,454,364			117,108,540		4
1,454,364			117,108,540		5
					6
					7
			291,469		8
		10,082,131	54,125,502		9
77,177		-10,072,203	216,891,982		10
			58,372,377		11
5,250		-9,928	132,495,949		12
11,900			36,174,782		13
			58,580,988		14
	-1,500,608		211,702		15
94,327	-1,500,608		557,144,751		16
					17
			2,347,703		18
5,012,718			483,327,506		19
1,575,307			746,553,533		20
2,295,582			231,513,400		21
388,286			171,710,366		22
645,386			88,753,280		23
	-1,900,632		-42,229,190		24
9,917,279	-1,900,632		1,681,976,598		25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
			10,000		37
			833,782		38
			4,616,105		39
			80,327,287		40
		-71,201	12,352,763		41
			10,369,755		42
			4,479,566		43
			15,479		44
		-71,201	113,004,737		45
10,011,606	-3,401,240	-71,201	2,352,126,086		46

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	11,562,813	2,379,014
49	(352) Structures and Improvements	7,602,090	654,372
50	(353) Station Equipment	150,858,263	7,573,647
51	(354) Towers and Fixtures	26,512,708	733,579
52	(355) Poles and Fixtures	91,930,234	21,146,470
53	(356) Overhead Conductors and Devices	77,700,649	502,792
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	1,095,500	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	367,262,257	32,989,874
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,942,732	-63,808
61	(361) Structures and Improvements	4,601,876	3,119,259
62	(362) Station Equipment	158,977,583	8,652,069
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	132,053,275	7,730,099
65	(365) Overhead Conductors and Devices	76,423,902	4,119,775
66	(366) Underground Conduit	103,785,336	4,010,231
67	(367) Underground Conductors and Devices	109,012,579	9,145,558
68	(368) Line Transformers	193,442,720	14,631,843
69	(369) Services	41,277,466	455,097
70	(370) Meters	41,932,523	1,889,953
71	(371) Installations on Customer Premises	11,470,987	574,179
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	9,960,171	176,649
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	886,881,150	54,440,904
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	43,057,352	2,796,196
88	(391) Office Furniture and Equipment	22,115,031	4,628,808
89	(392) Transportation Equipment	30,418,393	714,595
90	(393) Stores Equipment	181,385	
91	(394) Tools, Shop and Garage Equipment	2,434,917	358,331
92	(395) Laboratory Equipment	2,073,457	291,338
93	(396) Power Operated Equipment	5,875,616	109,278
94	(397) Communication Equipment	27,141,052	1,182,123
95	(398) Miscellaneous Equipment	2,167,129	743,485
96	SUBTOTAL (Enter Total of lines 86 thru 95)	136,363,543	10,824,154
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)	136,363,543	10,824,154
100	TOTAL (Accounts 101 and 106)	3,722,491,248	250,443,671
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)	3,722,491,248	250,443,671

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	/ /	End of 2013/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			13,941,827		48
56,356		42,892	8,242,998		49
7,416,633		-49,207	150,966,070		50
			27,246,287		51
			113,076,704		52
8,505			78,194,936		53
					54
					55
			1,095,500		56
					57
7,481,494		-6,315	392,764,322		58
					59
			3,878,924		60
		6,315	7,727,450		61
-1,800			167,631,452		62
					63
974,873		658	138,809,159		64
693,926			79,849,751		65
142,322			107,653,245		66
551,540			117,606,597		67
1,198,457		-658	206,875,448		68
			41,732,563		69
265,688			43,556,788		70
206,466			11,838,700		71
					72
31,502			10,105,318		73
					74
4,062,974		6,315	937,265,395		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			899,211		86
			45,853,548		87
4,923,306			21,820,533		88
569,565			30,563,423		89
			181,385		90
			2,793,248		91
194,138			2,170,657		92
15,341			5,969,553		93
2,766,734		71,201	25,627,642		94
207,260			2,703,354		95
8,676,344		71,201	138,582,554		96
					97
					98
8,676,344		71,201	138,582,554		99
31,686,782	-3,401,240		3,937,846,897		100
					101
					102
					103
31,686,782	-3,401,240		3,937,846,897		104

Schedule Page: 204 Line No.: 15 Column: e

Represents an adjustment to the existing ARO resulting from a change to the probability of extending Four Corners' operating term.

Schedule Page: 204 Line No.: 24 Column: e

Represents an adjustment to the existing ARO resulting from decreases in the estimated cash flows due to implementing the 2013 Palo Verde Decommissioning Study.

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	/ /	End of 2013/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	MONTANA POWER STATION	108,712,453
2	PALO VERDE CAPITAL IMPROVEMENTS	75,040,012
3	DIAMOND HEAD SUBSTATION	6,992,954
4	DISTRIBUTION COMMERCIAL CONSTRUCTION - TX	5,712,679
5	EASTSIDE DISTRIBUTION OPERATIONS CENTER	4,622,640
6	INFORMATION TECHNOLOGY HARDWARE & SOFTWARE PROJECTS	3,683,520
7	DISTRIBUTION RESIDENTIAL CONSTRUCTION - TX	3,671,060
8	DISTRIBUTION BETTERMENT - TX	3,065,436
9	FACILITIES SERVICES STRUCTURAL IMPROVEMENTS	2,892,562
10	MONTANA POWER TRANSMISSION SUBSTATION	2,270,077
11	AUSTIN SUBSTATION REGULATOR REPLACEMENT	2,266,270
12	FOUR CORNERS CAPITAL IMPROVEMENT	2,245,066
13	SUNSET SUBSTATION UPGRADES	2,110,766
14	ARROYO PHASE SHIFTER	2,055,596
15	DISTRIBUTION SUBSTATION TRANSFORMERS REPLACEMENTS - TX	1,848,217
16	TRANSMISSION CAPITAL IMPROVEMENT	1,840,187
17	UTEP FEEDER IMPROVEMENTS	1,636,607
18	PATRIOT SUBSTATION	1,586,252
19	LANE TO COPPER TRANSMISSION LINE REBUILD	1,586,164
20	NEWMAN UNIT 2 OUTAGE	1,385,398
21	RTU SUBSTATIONS COMMUNICATION UPGRADES	1,362,597
22	MILAGRO TO LEO TRANSMISSION LINE REBUILD	1,296,397
23	CHAPARRAL SUBSTATION SWITCHGEAR EXPANSION	1,280,903
24	DISTRIBUTION SUBSTATION BREAKERS REPLACEMENTS - TX	1,280,408
25	DISTRIBUTION WORK MANAGEMENT & GIS SYSTEM UPGRADE	1,209,597
26	SPARKS TO WRANGLER TRANSMISSION LINE REBUILD	1,142,117
27	AFTON TO AIRPORT TRANSMISSION LINE	1,104,728
28	RIO GRANDE TO SUNSET TRANSMISSION LINE REBUILD	1,099,469
29	NEWMAN STATION STEAM & WATER SAMPLE SYSTEMS	1,081,761
30	RIO GRANDE CIRCUIT BREAKERS REPLACEMENT	1,018,711
31	GLOBAL REACH TRANSMISSION LINE	1,000,838
32	MINOR PROJECTS	34,545,419
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	282,646,861

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	1,992,621,577	1,992,621,577		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	70,251,454	70,251,454		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-1,225,519	-1,225,519		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	69,025,935	69,025,935		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	30,601,120	30,601,120		
13	Cost of Removal	2,660,996	2,660,996		
14	Salvage (Credit)	3,922,530	3,922,530		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	29,339,586	29,339,586		
16	Other Debit or Cr. Items (Describe, details in footnote):	-14,202	-14,202		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,032,293,724	2,032,293,724		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	260,041,558	260,041,558		
21	Nuclear Production	1,189,614,396	1,189,614,396		
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production	12,690,012	12,690,012		
25	Transmission	198,028,144	198,028,144		
26	Distribution	308,025,623	308,025,623		
27	Regional Transmission and Market Operation				
28	General	63,893,991	63,893,991		
29	TOTAL (Enter Total of lines 20 thru 28)	2,032,293,724	2,032,293,724		

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	/ /	2013/Q4

FOOTNOTE DATA

Schedule Page: 219 Line No.: 16 Column: c

Reclass from FERC account 108 to FERC account 111

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	/ /	End of 2013/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		3,904,735
7				
8	Accumulated Deficit			-3,886,045
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
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30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	19,690

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	/ /	End of 2013/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
	-3,904,735			6
				7
-8,264	3,894,309			8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
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				38
				39
				40
				41
-8,264	-11,426			42

Schedule Page: 224 Line No.: 1 Column: a

MiraSol Energy Services, Inc. (“MiraSol”), the Company’s wholly owned subsidiary, provided energy efficiency products and discontinued these activities in 2002. The Company dissolved MiraSol in the fourth quarter of 2013. At the time it was dissolved, MiraSol’s net assets and stockholders’ equity totaled less than $0.1 million.

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

Represents the necessary entry to dissolve MiraSol.

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	/ /	End of 2013/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,394,321	1,297,394	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)	28,794,475	29,820,107	Production
8	Transmission Plant (Estimated)	4,561,943	5,453,505	Transmission
9	Distribution Plant (Estimated)	5,573,949	7,093,845	Distribution
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,044,813	2,321,216	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	40,975,180	44,688,673	
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)	433	-8,972	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	42,369,934	45,977,095	

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	/ /	End of 2013/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)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	12,946.00		359.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	346.00			
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	13,292.00		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				

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.

2015		2016		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		9,693.00		23,716.00		1
								2
								3
						346.00		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		9,693.00		24,062.00		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: d

Represents allowances allocated to the Company by the Environmental Protection Agency ("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 2017 and beyond.

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

Represents allowances banked by the Company through December 31, 2012.

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

The Company has not purchased any allowances; however, at December 30, 2013 SO2 allowances were trading at $0.75 per ton (allowance).

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

Represents (i) 13 allowances withheld by the EPA and (ii) 359 allowances allocated to the Company by the EPA based on our current electric generation and the current regulatory framework.

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	/ /	End of 2013/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	-233.00	-12,331		
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	885.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Evolution Markets	350.00	13,300		
10					
11					
12					
13					
14					
15	Total	350.00	13,300		
16					
17	Relinquished During Year:				
18	Charges to Account 509	806.00	37,076		
19	Other:				
20		940.00	-1,132		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	-744.00	-34,975		
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	/ /	End of 2013/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.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						-233.00	-12,331	1
								2
								3
						885.00		4
								5
								6
								7
								8
						350.00	13,300	9
								10
								11
								12
								13
								14
						350.00	13,300	15
								16
								17
						806.00	37,076	18
								19
						940.00	-1,132	20
								21
								22
								23
								24
								25
								26
								27
								28
						-744.00	-34,975	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 2013 compliance year.

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

Represents the accrual related to the NOx allowances expected to be purchased for the 2013 compliance year.

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

Includes an adjustment of (i) 55 NOx allowances to true-up to the 2012 actual shortage and (ii) 885 NOx allowances to reflect the application of the EPA issued emission allowances for 2013.

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

Represents the NOx allowance cost adjustment to true-up to the 2012 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	/ /	End of 2013/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	Montana Pwr Stat SIS & Fac Studies	304,939	186-000	(195,061)	186-000
23	Newman Solar Facilities Study	35,786	186-000	(5,214)	186-000
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	105,218,515	21,004,871	various	16,193,085	110,030,301
2						
3	Rio Grande Resources Trust:					
4	Nuclear Fuel Postload Daily Finance Charge	4,148,174	3,379,876	518	3,039,739	4,488,311
5						
6	Coal Reclamation	5,472,930		501/431	1,183,237	4,289,693
7						
8	Net Undercollection of Fuel Revenues:					
9	Texas		7,204,850			7,204,850
10	FERC		42,764			42,764
11						
12	Texas:					
13	2012 Rate Case Cost	2,335,230		928	1,754,326	580,904
14						
15	Texas Military Base Discount and Recovery	2,116,432	3,198,419	142	4,556,183	758,668
16						
17	Texas Energy Efficiency	536,394			536,394	
18						
19	New Mexico Renewable Energy Cost:					
20	Renewable Procurement Plan	139,248	262			139,510
21	Renewable Energy Credits	4,033,255	799,738			4,832,993
22						
23	New Mexico:					
24	2010 FPPCAC Audit	432,575		928000	53	432,522
25						
26	Palo Verde Deferred Depreciation	5,024,137		407.3	152,184	4,871,953
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	129,456,890	35,630,780		27,415,201	137,672,469

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

Amortization period ranges from 5 to 40 years.

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

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

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

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 termination date of the 50-year participation agreement among the owners of the Four Corners generating facility. In the Company's Texas jurisdiction, the recovery of final reclamation costs was approved as a component of reconcilable fuel in the Final Order of PUCT Docket No. 38361 issued January 27, 2011 to be amortized over a 113 month period beginning March 2007 through July 2016. 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.: 8 Column: a

At December 31, 2013, the Company had a net undercollection of fuel revenues.

Schedule Page: 232 Line No.: 13 Column: f

Balance of rate case costs related to PUCT Docket No. 40094 which are amortized over a two year period beginning May 2012.

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

PURA Section 36.354 requires that each electric utility provide Military Base Rate discounts to military bases in areas where customer choice is not available. In accordance with the Final Order in Docket No. 37690, 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: a

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. At December 31, 2013, the Company had overcollected energy efficiency program costs. The overcollection is presented as a regulatory liability in account 254.

Schedule Page: 232 Line No.: 20 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.: 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.: 24 Column: a

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.: 26 Column: a

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	/ /	End of 2013/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		109,230	131	41,000	68,230
2						
3	Miscellaneous	43,519	108,340	Various	112,470	39,389
4						
5	Reimbursable Transmission &					
6	Distribution Projects	213,107	2,126,609	131	1,550,353	789,363
7						
8	El Paso Water Utilities Land					
9	Lease	1,754,504	343,391	507	441,777	1,656,118
10						
11	Palo Verde Water					
12	Agreement Deposit	3,228,693	1,065,765			4,294,458
13						
14						
15						
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45						
46						
47	Misc. Work in Progress	49,400				-13,413
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	5,289,223				6,834,145

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: a

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	/ /	End of 2013/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		222,326,485	202,347,808
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	222,326,485	202,347,808
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	2,053,850	1,918,883
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	224,380,335	204,266,691

Notes

Schedule Page: 234 Line No.: 8 Column: c

< Page 234 Line 2 Column (a) >

	Balance at Beginning of Year	Balance at End of Year
ELECTRIC		
Deferred tax assets:		
Plant, principally due to capitalized costs	45,390,460	49,089,532
Benefit of tax loss carryforwards	7,459,704	17,906,619
Pensions and benefits	83,480,581	51,500,837
Alternative minimum tax credit carryforward	21,599,450	21,637,728
Regulatory liabilities related to income taxes	13,523,331	10,411,495
Asset retirement obligation	23,428,204	25,323,931
Deferred fuel	1,804,753	0
Debt	7,093,235	6,949,498
Other	18,546,767	19,528,168
Net deferred tax assets	222,326,485	202,347,808

< Page 234 Line 17 Column (a) >

	Balance at Beginning of Year	Balance at End of Year
OTHER (Specify)		
Deferred tax assets:		
Other capitalized costs	0	0
Decommissioning costs	2,053,850	1,918,883
Net deferred tax assets	2,053,850	1,918,883
Total Account 190	224,380,335	204,266,691

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, 2013, 490,362			
12	unissued shares of Common Stock of the			
13	Company were reserved for future			
14	allocations under the 1999 Long-Term			
15	Incentive Plan and 2007 Long-Term			
16	Incentive Plan.			
17				
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28	Note: For additional information see the			
29	El Paso Electric Company 2013 Form 10-K			
30	filed with the SEC February 26, 2014.			
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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	/ /	End of 2013/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
65,759,625	65,695,588	25,492,919	424,646,957			3
65,759,625	65,695,588	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	/ /	End of 2013/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	2,205,552
4		
5		
6		
7		
8		
9		
10		
11		
12		
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39		
40	TOTAL	2,205,552

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

Represents deferred compensation related to grants of performance share awards to certain officers in 2011, 2012, and 2013 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.

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	/ /	End of 2013/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

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	/ /	End of 2013/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	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	2012 Series A Palo Verde Pollution Control Bonds	59,235,000	896,854
6	2012 Series A Four Corners Pollution Control Bonds	33,300,000	912,545
7			
8	Subtotal	193,135,000	3,789,455
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	2012 Senior Notes	150,000,000	1,338,657
21			318,000 D
22	Treasury Rate Lock Agreements		
23	Subtotal	700,000,000	12,203,578
24			
25	Interest on obligations under capital lease (Rio Grande Resources Trust):		
26	$110 million RGRT Senior Notes		
27	Revolving Credit Facility		
28			
29			
30			
31			
32			
33	TOTAL	893,135,000	15,993,033

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						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
08/28/12	08/01/42	08/28/12	08/01/42	59,235,000	2,665,575	5
08/28/12	06/01/32	08/28/12	06/01/32	33,300,000	624,375	6
						7
				193,135,000	10,583,450	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
12/06/12	12/15/22	12/06/12	12/15/22	150,000,000	4,936,250	20
						21
					410,676	22
				700,000,000	40,596,926	23
						24
						25
					5,053,500	26
					453,863	27
						28
						29
						30
						31
						32
				893,135,000	56,687,739	33

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

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

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

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

Schedule Page: 256 Line No.: 27 Column: b

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

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)	92,779,951
2		
3		
4	Taxable Income Not Reported on Books	
5	(see page 261 footnote)	12,132,735
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	(see page 261 footnote)	14,783,164
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	(see page 261 footnote)	-13,280,012
16		
17	Federal Income Taxes (detail below)	42,098,069
18		
19	Deductions on Return Not Charged Against Book Income	
20	(see page 261 footnote)	-156,982,346
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-8,468,439
28	Show Computation of Tax:	
29		
30		
31	Tax computed at statutory rate (see page 261 footnote)	47,081,268
32	ITC Amortization Net of Deferred Taxes	-704,794
33	Amortization of Excess Deferred Taxes	-717,132
34	Permanent differences	-1,047,807
35	State Income Taxes (Federal effect)	126,040
36	Amortization of Regulatory Assets	-379,505
37	Allowance for equity Funds Used During Construction	-2,075,545
38	Other	-184,456
39		
40		
41		
42	Total federal income tax expense (benefit)	42,098,069
43		
44		

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

Contributions in aid of construction	1,248,976
Unbilled Revenue	822,313
Capitalized Construction Interest	9,959,636
Other	101,810
Taxable Income Not Reported on Books	12,132,735

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

Meals and Entertainment	167,017
Lobbying	656,927
Capitalized A&G	5,996,137
Debt Issuance Costs	373,620
Environmental Cost Accrual	350,263
Coal Reclamation	1,000,515
FAS 143 ARO	5,867,284
Penalties	15,209
Other	356,192
Deductions Recorded on Books Not Deducted for Return	14,783,164

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

Decommissioning Trust Interest Net of Fees	(1,281,237)
AFUDC	(11,998,775)
Income Reported on Books Not Included in Return	(13,280,012)

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

Employee Benefits	(4,890,164)
Legal Expense Accrual	(244,415)
Depreciation and Amortization Differences	(111,634,833)
Deferred Fuel	(10,842,829)
Section 174 R&D	(3,784,168)
Deferred State Taxes and Reserves	(414,063)
Decommissioning Costs	(8,815,000)
Project Care Bravo	(692,302)
Repair Allowance	(12,000,000)
Taxes Other Than Federal	(148,270)
Uncollectible Accounts Receivable	(644,783)
Other	(2,871,519)
Deductions on Return not Charged Against Book Income	(156,982,346)

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

Net Income	92,779,951
Federal and State Income Tax Expense	41,737,957
Pre-Tax Income	134,517,908
Tax Rate	35%
Tax Computed at Statutory Rate	47,081,268

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	-91,692		1,625,499	970,000	
3	Prior Years	376,867		131,141	106,767	
4	FUTA			45,033	45,033	
5	Insurance Contributions			6,118,201	6,118,201	
6	SUBTOTAL	285,175		7,919,874	7,240,001	
7						
8	State County & Local - TX					
9	Ad Valorem	6,810,779		7,669,862	6,829,460	
10	Gross Receipts	1,519,542		10,116,204	10,108,154	
11	Unemployment			86,385	86,385	
12	Franchise Tax / Margin Tax	1,809,378	2,337,540	1,162,125	49,126	
13	Use Tax	382,078		2,380,746	2,257,585	
14	Regulatory Commission	443,097		970,180	956,337	
15	Franchise Fees (OSR)	4,043,812	11,396	19,741,294	20,019,704	
16	SUBTOTAL	15,008,686	2,348,936	42,126,796	40,306,751	
17						
18	State County & Local - NM					
19	Ad Valorem	1,693,243	1,816	3,719,598	3,553,776	
20	Income	1,725	892,032	19,263	-881,974	
21	Unemployment			22,928	22,928	
22	Compensating	-58,085		634,338	856,374	
23	Regulatory Commission	956,759		952,093	949,329	
24	Francise Fees (OSR)	131,886	270,299	3,439,102	3,237,334	
25	L.C. Fran Pumping Facility					
26	Payroll Taxes			161,721	161,721	
27	Workers Compensation Fee					
28						
29						
30	Other Taxes	-558		752	194	
31	SUBTOTAL	2,724,970	1,164,147	8,949,795	7,899,682	
32						
33						
34	State County & Local - AZ					
35	Ad Valorem	3,156,047		7,129,634	6,721,169	
36	Income	-113,189	1,692,988	-1,129,034		
37	Palo Verde Payroll Taxes			8,562	8,562	
38	Sales & Use Taxes	96			96	
39	SUBTOTAL	3,042,954	1,692,988	6,009,162	6,729,827	
40						
41	TOTAL	21,061,785	5,206,071	65,005,627	62,176,261	

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
563,807		-836,873			2,462,372	2
401,241		-1,285,148			1,416,289	3
		34,181			10,852	4
		4,643,877			1,474,324	5
965,048		2,556,037			5,363,837	6
						7
						8
7,651,181		7,669,862				9
1,527,592		10,116,204				10
		65,569			20,816	11
584,837		1,162,125				12
505,239		-424,638			2,805,384	13
456,940		970,180				14
3,765,793	11,787	19,741,294				15
14,491,582	11,787	39,300,596			2,826,200	16
						17
						18
1,859,065	1,816	3,719,598				19
16,430	5,500	-105,765			125,028	20
		17,403			5,525	21
-280,121		7,102			627,236	22
959,523		952,093				23
138,302	74,947	98,126			3,340,976	24
						25
		161,721				26
						27
						28
						29
		-12,721			13,473	30
2,693,199	82,263	4,837,557			4,112,238	31
						32
						33
						34
3,564,512		7,129,634				35
-1,433,167	1,502,044	-1,185,053			56,019	36
		2,857,522			-2,848,960	37
						38
2,131,345	1,502,044	8,802,103			-2,792,941	39
						40
20,281,174	1,596,094	55,496,293			9,509,334	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	/ /	End of 2013/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%						
3	4%						
4	7%						
5	10%	24,077,037			411.4/420.0	1,067,797	
6	30%	266,878	411.4	381,177	411.4	16,500	
7							
8	TOTAL	24,343,915		381,177		1,084,297	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10			411.4	381,177	411.4	1,118,292	
11					420.0	-33,995	
12							
13							
14							
15							
16							
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18							
19							
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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	/ /	End of 2013/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
23,009,240	25 years		5
631,555	25 years		6
			7
23,640,795			8
			9
-737,115			10
33,995			11
			12
			13
			14
			15
			16
			17
			18
			19
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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	/ /	End of 2013/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	Tucson Electric Power				133,480	133,480
5						
6	OPEB					
7	Palo Verde	23,683	131	23,683		
8						
9	Environmental Accrual	200,000			350,000	550,000
10						
11	Texas Docket 23530 Settlement	2,125,977	131	696,605	4,303	1,433,675
12						
13	Contribution in Aid of Construct.	247,682	186	247,682	933,921	933,921
14						
15	Other	552,276	131	408,502	269,252	413,026
16						
17						
18						
19						
20						
21						
22						
23						
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26						
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43						
44						
45						
46						
47	TOTAL	14,849,618		1,376,472	1,690,956	15,164,102

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	/ /	End of 2013/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	492,091,591	68,020,673	12,174,760
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	492,091,591	68,020,673	12,174,760
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	492,091,591	68,020,673	12,174,760
10	Classification of TOTAL			
11	Federal Income Tax	492,091,591	68,020,673	12,174,760
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					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
653				various	270,824	548,208,981	2
							3
							4
653					270,824	548,208,981	5
							6
							7
							8
653					270,824	548,208,981	9
							10
653					270,824	548,208,981	11
							12
							13

NOTES (Continued)

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

	Balance at Beginning of Year	Balance at End of Year
Electric:		
Plant, principally due to depreciation and basis differences	$ 432,290,718	$ 481,753,151
Regulatory assets related to income taxes	35,645,182	37,720,727
Decommissioning	24,155,691	26,744,833
Deferred Fuel	-	1,990,270
Total - Electric Other	$ 492,091,591	$ 548,208,981

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	/ /	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Tax	25,235,651	2,561,750	2,420,554
4				
5	Deferred State Tax	34,589,736		
6				
7	FIT on SIT	13,278,092		
8	Other - Debt	26		
9	TOTAL Electric (Total of lines 3 thru 8)	73,103,505	2,561,750	2,420,554
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)	73,103,505	2,561,750	2,420,554
20	Classification of TOTAL			
21	Federal Income Tax	38,513,769	2,561,750	2,420,554
22	State Income Tax	34,589,736		
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		254.3	2,582,530	182.3	3,574,644	26,368,961	3
							4
		254.3	5,881,340	182.3	9,172,403	37,880,799	5
							6
		254.3	839,586	182.3	2,045,887	14,484,393	7
		254.3	1	182.3		25	8
			9,303,457		14,792,934	78,734,178	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
			9,303,457		14,792,934	78,734,178	19
							20
			3,422,117		5,620,531	40,853,379	21
			5,881,340		9,172,403	37,880,799	22
							23

NOTES (Continued)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Regulatory Tax Liabilities	50,306,082	various	3,610,000	3,792,779	50,488,861
2						
3	Net Overcollection of Fuel Revenues:					
4	Texas	2,294,928	440s	2,294,928		
5	New Mexico	2,279,504	440s	1,231,679		1,047,825
6	FERC	68,609	440s	68,609		
7						
8	New Mexico Energy Efficiency Program	926,237	182.3	3,205,686	5,924,923	3,645,474
9						
10	Texas Energy Efficiency Program		182.3	5,016,211	5,378,314	362,103
11						
12						
13						
14						
15						
16						
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40						
41	TOTAL	55,875,360		15,427,113	15,096,016	55,544,263

Schedule Page: 278 Line No.: 1 Column: b

Amortization period ranges from 5 to 40 years.

Schedule Page: 278 Line No.: 3 Column: a

At December 31, 2013, the Company had a net undercollection of fuel revenues.

Schedule Page: 278 Line No.: 8 Column: a

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

Schedule Page: 278 Line No.: 10 Column: a

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

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	/ /	End of 2013/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	313,138,900	299,370,743
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	250,838,821	244,955,724
5	Large (or Ind.) (See Instr. 4)	67,858,998	65,302,794
6	(444) Public Street and Highway Lighting	5,803,061	5,543,637
7	(445) Other Sales to Public Authorities	134,921,940	129,539,438
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	772,561,720	744,712,336
11	(447) Sales for Resale	86,539,995	76,465,581
12	TOTAL Sales of Electricity	859,101,715	821,177,917
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	859,101,715	821,177,917
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,401,678	1,371,365
17	(451) Miscellaneous Service Revenues	4,225,983	5,070,186
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	2,824,325	2,529,880
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	258,402	389,503
22	(456.1) Revenues from Transmission of Electricity of Others	22,549,607	22,342,319
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	31,259,995	31,703,253
27	TOTAL Electric Operating Revenues	890,361,710	852,881,170

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
2,679,262	2,648,348	347,891	343,409	2
				3
2,349,148	2,366,541	38,836	38,601	4
1,095,379	1,082,973	50	50	5
43,802	42,872	170	174	6
1,578,805	1,574,734	4,827	4,654	7
				8
				9
7,746,396	7,715,468	391,774	386,888	10
3,137,845	3,128,976	27	29	11
10,884,241	10,844,444	391,801	386,917	12
				13
10,884,241	10,844,444	391,801	386,917	14

Line 12, column (b) includes $ 1,886,000 of unbilled revenues.

Line 12, column (d) includes 35,515 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 10 Column: g

The number of retail customers presented are based on the number of service locations. Previous presentations of the number of retail customers in 2012 were based on the number of bills rendered including consolidated bills for customers operating multiple facilities. Management believes the number of service locations provides a more accurate indicator of customers served than the number of bills rendered.

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

Includes 603,991 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 450,578 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 603,991 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 450,578 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 603,991 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 450,578 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 2013
Non Pay Reconnect Charges	1,843,837
Name Change/Cut in Charge	1,059,004
New Service Charges	319,582
Overhead/Underground Connection Charges	199,815
Texas Energy Efficiency Bonus	465,275
Misc Other	338,470
Total	4,225,983

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

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

	December 2012
Non Pay Reconnect Charges	1,926,006
Name Change/Cut in Charge	1,034,305
New Service Charges	329,237
Overhead/Underground Connection Charges	211,499
Texas Energy Efficiency Bonus	1,260,894
Misc Other	308,245
Total	5,070,186

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

Includes $257,209 related to the Company's 15.8% share of Palo Verde other electric revenues from APS.

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

Includes $389,503 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	/ /	End of 2013/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	1,989,994	224,602,242	265,345	7,500	0.1129
4	28 Private Area Lighting Service	1,961	301,947	230	8,526	0.1540
5	TXVRE-R Voluntary Renewable		31,494			
6	Deferred Fuel		3,126,789			
7	Unbilled Revenue	10,189	828,000			0.0813
8	Renewable Energy Credit		-31,659			
9	Power Factor Adjustment		770,135			
10						
11	RESIDENTIAL SALES-NM					
12	01 Residential Service	669,912	82,143,025	81,992	8,170	0.1226
13	12 Private Area Lighting Service	2,448	572,921	324	7,556	0.2340
14	Deferred Fuel		480,739			
15	Unbilled Revenue	4,758	321,000			0.0675
16	Renewable Energy Credit		-7,733			
17						
18	Total (440)	2,679,262	313,138,900	347,891	7,701	0.1169
19						
20						
21	(442)					
22	C & I SALES SMALL-TX					
23	02 Small Commercial Service	232,480	32,542,411	22,436	10,362	0.1400
24	07 Outdoor Recreational Lighting	349	37,924	15	23,267	0.1087
25	22 Irrigation Service	3,185	368,943	78	40,833	0.1158
26	24 General Service	1,346,662	132,021,874	6,255	215,294	0.0980
27	25 Large Power Service	221,948	18,711,905	58	3,826,690	0.0843
28	28 Private Area Lighting Service	14,830	1,820,935	434	34,171	0.1228
29	34 Cotton Gin Service	681	72,147	1	681,000	0.1059
30	TXVRE-C Voluntary Renewable		884			
31	Deferred Fuel		2,907,661			
32	Unbilled Revenue	6,417	399,000			0.0622
33	Renewable Energy Credit		-902			
34						
35	C & I SALES SMALL-NM					
36	03 Small Commercial Service	154,743	22,221,091	8,151	18,985	0.1436
37	04 General Service	278,182	29,665,631	571	487,184	0.1066
38	05 Irrigation Service	52,231	5,940,155	703	74,297	0.1137
39	08 Municipal Water Pumping	2,010	195,892	24	83,750	0.0975
40	09 Large Power Service	24,695	2,313,325	4	6,173,750	0.0937
41	TOTAL Billed	7,710,881	770,675,720	391,774	19,682	0.0999
42	Total Unbilled Rev.(See Instr. 6)	35,515	1,886,000	0	0	0.0531
43	TOTAL	7,746,396	772,561,720	391,774	19,773	0.0997

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	/ /	End of 2013/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	12 Private Area Lighting Service	1,999	455,110	70	28,557	0.2277
2	19 Seasonal Agr. Processing Svc.	4,503	611,976	25	180,120	0.1359
3	25 Outdoor Recreational Lighting	111	15,980	10	11,100	0.1440
4	29 Interrupt. Svc. for Lg Power	2,213	125,411	1	2,213,000	0.0567
5	Deferred Fuel		344,392			
6	Unbilled Revenue	1,909	127,000			0.0665
7	Renewable Energy Credit		-8,224			
8						
9	C & I SALES LARGE-TX					
10	15 Electrolytic Refining	55,508	3,692,249	1	55,508,000	0.0665
11	25 Large Power Service	319,181	26,821,864	34	9,387,676	0.0840
12	26 Petroleum Refinery Service	331,439	19,786,484	1	331,439,000	0.0597
13	28 Private Area Lighting Service	247	29,193			0.1182
14	30 Electric Furnace	21,533	1,732,012	1	21,533,000	0.0804
15	38 Interrupt. Svc. for Lg Power	289,060	9,458,089	6	48,176,667	0.0327
16	Deferred Fuel		1,545,655			
17	Unbilled Revenue	5,948	78,000			0.0131
18	Power Factor Adjustment		-1,105,038			
19						
20	C & I SALES LARGE-NM					
21	09 Large Power Service	48,739	4,439,672	4	12,184,750	0.0911
22	29 Interrupt. Svc. for Lg Power	23,583	1,260,532	3	7,861,000	0.0535
23	Deferred Fuel		72,586			
24	Unbilled Revenue	141	-4,000			-0.0284
25						
26	Total (442)	3,444,527	318,697,819	38,886	88,580	0.0925
27						
28	(444)					
29	PUBLIC ST. & HIGHWAY LIGHT-TX					
30	08 Gov't Street Lights and Signal	40,355	5,163,495	151	267,252	0.1280
31	Deferred Fuel		47,607			
32	Unbilled Revenue	155	14,000			0.0903
33	Power Factor Adjustment		15,913			
34						
35	PUBLIC ST. & HIGHWAY LIGHT-NM					
36	11 Municipal St. Lighting and Sig	3,282	558,250	19	172,737	0.1701
37	Deferred Fuel		2,796			
38	Unbilled Revenue	10	1,000			0.1000
39						
40	Total (444)	43,802	5,803,061	170	257,659	0.1325
41	TOTAL Billed	7,710,881	770,675,720	391,774	19,682	0.0999
42	Total Unbilled Rev.(See Instr. 6)	35,515	1,886,000	0	0	0.0531
43	TOTAL	7,746,396	772,561,720	391,774	19,773	0.0997

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	/ /	End of 2013/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						
2	(445)					
3	OTHER SALES PUB AUTH-TX					
4	01 Residential Service	364	46,647	126	2,889	0.1282
5	02 Small Commercial Service	10,361	1,435,916	1,072	9,665	0.1386
6	07 Outdoor Recreational Lighting	4,733	506,539	177	26,740	0.1070
7	11 Municipal Pumping Service	178,032	13,935,274	412	432,117	0.0783
8	22 Irrigation	2,050	224,986	14	146,429	0.1097
9	24 General Service	136,624	13,251,578	442	309,104	0.0970
10	25 Large Power Service	71,107	5,814,948	10	7,110,700	0.0818
11	28 Private Area Lighting	9,650	1,115,636	132	73,106	0.1156
12	31 Military Reservation Service	338,224	23,480,051	1	338,224,000	0.0694
13	38 Interruptible Service Large Po	19,421	663,308	1	19,421,000	0.0342
14	41 City and County Service	306,367	30,251,107	1,072	285,790	0.0987
15	43 University Service	62,182	4,067,236	2	31,091,000	0.0654
16	45 Supplemental Power	22,389	1,612,724	1	22,389,000	0.0720
17	Deferred Fuel		1,878,196			
18	Unbilled Revenue	4,482	58,000			0.0129
19	University Discount		-332,403			
20	Power Factor Adjustment		318,992			
21						
22	OTHER SALES PUB AUTH-NM					
23	01 Residential Service	127	17,070	35	3,629	0.1344
24	03 Small Commercial Service	6,308	957,859	274	23,022	0.1518
25	04 General Service	25,587	2,642,199	51	501,706	0.1033
26	05 Irrigation Service	156	18,493	5	31,200	0.1185
27	07 City and County Service	71,507	8,517,726	815	87,739	0.1191
28	08 Municipal Pumping Service	30,467	2,881,503	128	238,023	0.0946
29	09 Large Power Service	56,565	5,025,465	6	9,427,500	0.0888
30	10 Military Research & Dev. Power	172,818	12,429,940	2	86,409,000	0.0719
31	12 Private Area Lighting	339	73,927	28	12,107	0.2181
32	25 Outdoor Recreational Lighting	547	71,405	20	27,350	0.1305
33	26 State University Service	46,892	3,578,521	1	46,892,000	0.0763
34	Deferred Fuel		331,165			
35	Unbilled Revenue	1,506	64,000			0.0425
36	Renewable Energy Credit		-16,068			
37						
38	Total (445)	1,578,805	134,921,940	4,827	327,078	0.0855
39						
40						
41	TOTAL Billed	7,710,881	770,675,720	391,774	19,682	0.0999
42	Total Unbilled Rev.(See Instr. 6)	35,515	1,886,000	0	0	0.0531
43	TOTAL	7,746,396	772,561,720	391,774	19,773	0.0997

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

Estimated Fuel Clause Revenues by Rate Schedule

(440) RESIDENTIAL SALES

TEXAS

01 Residential Service	$ 45,960,582
28 Private Area Lighting Service	45,567
Power Factor Adjustment	770,135
Deferred Fuel	3,126,789
Total - Texas	49,903,073

NEW MEXICO

01 Residential Service	(3,440,037)
12 Private Area Lighting Service	(14,468)
Deferred Fuel	480,739
Total - New Mexico	(2,973,766)
Total (440)	$ 46,929,307

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

There were less than 1,250 duplicate customers for all rates schedules combined in 2013.

Schedule Page: 304 Line No.: 21 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(442) COMMERCIAL AND INDUSTRIAL SALES

SMALL - TEXAS

02 Small Commercial Service	$ 5,380,819
07 Outdoor Recreational Lighting	8,144
22 Irrigation Service	73,210
24 General Service	31,173,443
25 Large Power Service	5,137,965
28 Private Area Lighting Service	345,582
34 Cotton Gin Service	16,901
Power Factor Adjustment	701,307
Deferred Fuel	2,907,661
Total - Texas	45,745,032

SMALL - NEW MEXICO

03 Small Commercial Service	(797,253)
04 General Service	(1,480,473)
05 Irrigation Service	(188,016)
08 Municipal Water Pumping	(9,907)
09 Large Power Service	(134,302)
12 Private Area Lighting Service	(11,843)
19 Seasonal Agr. Processing Svc.	(38,239)
25 Outdoor Recreational Lighting	(518)
29 Interrup. Svc for Lg Power	(9,302)
Deferred Fuel	344,392
Total - New Mexico	(2,325,461)

LARGE - TEXAS

15 Electrolytic refining	1,235,139

25	Large Power Service	7,359,582
26	Petroleum Refinery Service	7,361,396
28	Private Area Lighting Service	5,760
30	Electric Furnace	478,469
38	Interruptible Svc for Large Power	6,446,929
	Power Factor Adjustment	383,077
	Deferred Fuel	1,545,655
	Total - Texas	24,816,007

LARGE - NEW MEXICO

09	Large Power Service	(272,978)
29	Interruptible Service Large Power	(133,414)
	Deferred Fuel	72,586
	Total - New Mexico	(333,806)
	Total (442)	$ 67,901,772

Schedule Page: 304.1 Line No.: 28 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(444) PUBLIC STREET AND HIGHWAY LIGHTING

TEXAS

08	Municipal St. Lights & Signals	$ 940,941
	Power Factor Adjustment	15,913
	Deferred Fuel	47,607
	Total - Texas	$1,004,461

NEW MEXICO

11	Municipal St. Lights & Signals	(19,348)
	Deferred Fuel	2,796
	Total - New Mexico	(16,552)
	Total (444)	$ 987,909

Schedule Page: 304.2 Line No.: 2 Column: c

Estimated Fuel Clause Revenues by Rate Schedule

(445) OTHER SALES TO PUBLIC AUTHORITIES

TEXAS

01	Residential Service	$ 8,398
02	Small Commercial Service	241,369
07	Outdoor Rec. Lighting Service	110,658
11	Municipal Pumping Service	4,103,416
22	Irrigation	47,417
24	General Service	3,164,732
25	Large Power Service	1,639,514
28	Private Area Lighting	224,956
31	Military Reservation Service	7,487,957
38	Interruptible Service for Large	438,678
41	City and County Service	7,077,330
43	University Service	1,419,603
45	Supplemental Power	509,957
	Power Factor Adjustment	440,113
	Deferred Fuel	1,878,196
	Total - Texas	28,792,294

NEW MEXICO

01	Residential Service	(722)
03	Small Commercial Service	(34,052)
04	General Service	(145,312)
05	Irrigation Service	(550)
07	City and County Service	(406,900)
08	Municipal Pumping	(159,695)
09	Large Power Service	(309,700)
10	Military Research & Dev. Power	(882,817)
12	Private Area Lighting	(2,009)
25	Outdoor Rec. Lighting Service	(3,070)
26	State University Service	(229,223)
	Deferred Fuel	331,165
	Total - New Mexico	(1,842,885)
	Total (445)	$ 26,949,409

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	/ /	End of 2013/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	Rio Grande Electric Cooperative, Inc.	RQ	18	8.5	14.6	11.3
2	Rio Grande Electric Cooperative, Inc.	AD	18			
3	Arizona Electric Power Cooperative	SF	1			
4	Arizona Public Service Company	SF	1			
5	Black Hills Power Inc	SF	1			
6	Cargill Power Markets, LLC	SF	1			
7	Citigroup Energy Inc.	SF	1			
8	City of Burbank California	SF	1			
9	Comision Federal de Electricidad	OS	N/A			
10	Constellation Energy Commodities Group	SF	1			
11	DB Energy Trading LLC	SF	1			
12	EDF Trading North America, LLC	OS	1			
13	EDF Trading North America, LLC	SF	1			
14	Exelon Generation Company	SF	1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
61,232	1,892,170	1,741,055	111,373	3,744,598	1
			-10,495	-10,495	2
13,945		337,570		337,570	3
10,460		303,295	9,330	312,625	4
51		2,091		2,091	5
17,749		645,386		645,386	6
92,821		2,997,758		2,997,758	7
7,970		269,610		269,610	8
10,500		724,500	-9,486	715,014	9
4,240		119,158		119,158	10
25		613		613	11
			36	36	12
82,602		2,644,219		2,644,219	13
34,737		1,072,856		1,072,856	14
61,232	1,892,170	1,741,055	111,373	3,744,598	
3,076,613	0	82,406,125	389,272	82,795,397	
3,137,845	**1,892,170**	**84,147,180**	**500,645**	**86,539,995**	

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	/ /	End of 2013/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	Gila River Power LLC	OS	1			
2	Gila River Power LLC	SF	1			
3	Freeport-McMoRan Copper & Gold Energy	LU	2			
4	Iberdrola Renewables, LLC	SF	1			
5	Imperial Irrigation District	SF	1			
6	Los Alamos County	OS	1			
7	Los Alamos County	SF	1			
8	J. Aron & Company	SF	1			
9	J.P. Morgan Ventures Energy Corporation	SF	1			
10	Los Angeles Department of Water and Pow	SF	1			
11	Macquarie Energy LLC	SF	1			
12	Morgan Stanley Capital Group, Inc.	SF	1			
13	Noble Americas Gas and Power Corp	SF	1			
14	PacifiCorp	SF	1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			4,059	4,059	1
23,631		764,157	1,172	765,329	2
603,991		1,238,182		1,238,182	3
8,200		266,318		266,318	4
2,107		82,684		82,684	5
			378,349	378,349	6
2,425		74,776		74,776	7
8,560		328,130		328,130	8
2,022		48,717		48,717	9
2,250		71,950		71,950	10
84,895		2,574,810	2,245	2,577,055	11
494,626		15,099,479	3,344	15,102,823	12
2,400		66,928		66,928	13
420		11,980		11,980	14
61,232	1,892,170	1,741,055	111,373	3,744,598	
3,076,613	0	82,406,125	389,272	82,795,397	
3,137,845	**1,892,170**	**84,147,180**	**500,645**	**86,539,995**	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PacifiCorp	SF	1			
2	Powerex Corp.	SF	1			
3	Public Service Company of Colorado	SF	1			
4	Public Service Company of New Mexico	OS	1			
5	Public Service Company of New Mexico	SF	1			
6	Salt River Project Agricultural Improv	SF	1			
7	Sempra Generation	OS	1			
8	Sempra Generation	SF	1			
9	Shell Energy North America (US), LP.	SF	2			
10	Southern California Edison Co	SF	1			
11	Southwestern Public Service Company	SF	1			
12	Tenaska Power Services Co	SF	1			
13	Transalta Energy Marketing (U.S.), Inc.	SF	1			
14	Tri-State G & T Association, Inc.	SF	1			
	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.
80		2,450		2,450	1
5,530		155,773		155,773	2
7,552		296,980		296,980	3
			2,620	2,620	4
31,870		1,125,547		1,125,547	5
114,032		4,317,001		4,317,001	6
			1,560	1,560	7
76,040		2,259,469		2,259,469	8
846,768		28,970,961	703	28,971,664	9
4,998		153,215		153,215	10
4,375		149,087		149,087	11
379,672		12,426,282		12,426,282	12
31,465		986,330		986,330	13
3,790		121,170		121,170	14
61,232	1,892,170	1,741,055	111,373	3,744,598	
3,076,613	0	82,406,125	389,272	82,795,397	
3,137,845	**1,892,170**	**84,147,180**	**500,645**	**86,539,995**	

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	/ /	End of 2013/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tucson Electric Power Company	OS	1			
2	Tucson Electric Power Company	SF	1			
3	UNS Electric Inc	SF	1			
4	WAPA - Desert SouthWest	SF	1			
5	Arizona Electric Power Cooperative	SF	104	N/A	N/A	N/A
6	Arizona Public Service Company	SF	104	N/A	N/A	N/A
7	HGMA	SF	104	N/A	N/A	N/A
8	IID	SF	104	N/A	N/A	N/A
9	Panda Gila River	SF	104	N/A	N/A	N/A
10	Public Service Company of New Mexico	SF	104	N/A	N/A	N/A
11	Sempra Generation	SF	104	N/A	N/A	N/A
12	Salt River Project Agricultural Improv	SF	104	N/A	N/A	N/A
13	Tucson Electric Power Company	SF	104	N/A	N/A	N/A
14	Tri-state G & T Association, Inc.	SF	104	N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			2,475	2,475	1
52,673		1,430,568		1,430,568	2
3,320		132,590		132,590	3
50		6,250		6,250	4
265		8,744		8,744	5
212		6,370		6,370	6
238		7,965		7,965	7
102		3,098		3,098	8
710		24,714	230	24,944	9
698		24,242		24,242	10
416		13,861	2,045	15,906	11
314		10,288		10,288	12
453		15,602		15,602	13
363		12,401	1,085	13,486	14
61,232	1,892,170	1,741,055	111,373	3,744,598	
3,076,613	0	82,406,125	389,272	82,795,397	
3,137,845	**1,892,170**	**84,147,180**	**500,645**	**86,539,995**	

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

Schedule Page: 310 Line No.: 1 Column: j
Represents Rio Grande Electric Cooperative ("RGEC") fuel adjustment clause designed to recover all eligible fuel costs allocable to RGEC.

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.: 9 Column: b
Firm and non-firm energy sale.

Schedule Page: 310 Line No.: 9 Column: j
Transmission and ancillary services persuant to Open Access Transmission Tarriff ("OATT") Schedule 4 - Energy Imbalance.

Schedule Page: 310 Line No.: 12 Column: b
Spinning reserves.

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

Schedule Page: 310.1 Line No.: 1 Column: b
Spinning reserves.

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

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

Schedule Page: 310.1 Line No.: 6 Column: b
Spinning reserves.

Schedule Page: 310.1 Line No.: 6 Column: j
Spinning reserves.

Schedule Page: 310.1 Line No.: 11 Column: j
Transmission services.

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

Schedule Page: 310.2 Line No.: 4 Column: b
Spinning reserves.

Schedule Page: 310.2 Line No.: 4 Column: j
Spinning reserves.

Schedule Page: 310.2 Line No.: 7 Column: b
Spinning reserves.

Schedule Page: 310.2 Line No.: 7 Column: j
Spinning reserves.

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

Schedule Page: 310.3 Line No.: 1 Column: b
Spinning reserves.

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

Schedule Page: 310.3 Line No.: 9 Column: j
Other Charges are for Southwest Reserve Sharing Group ("SRSG") charge received.

Schedule Page: 310.3 Line No.: 11 Column: j

Other Charges are for SRSG charge received.

Schedule Page: 310.3 Line No.: 14 Column: j

Other Charges are for SRSG charge 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	/ /	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,967,278	2,095,157
5	(501) Fuel	171,009,451	138,989,057
6	(502) Steam Expenses	3,691,798	3,894,373
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	3,056,908	3,366,611
10	(506) Miscellaneous Steam Power Expenses	5,489,451	4,460,931
11	(507) Rents	1,299,858	1,443,288
12	(509) Allowances	35,944	65,064
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	186,550,688	154,314,481
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,711,078	1,500,114
16	(511) Maintenance of Structures	1,249,958	1,384,058
17	(512) Maintenance of Boiler Plant	9,519,426	8,919,057
18	(513) Maintenance of Electric Plant	8,812,888	10,324,222
19	(514) Maintenance of Miscellaneous Steam Plant	2,453,827	2,389,310
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,747,177	24,516,761
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	210,297,865	178,831,242
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	12,557,865	13,733,764
25	(518) Fuel	49,180,710	49,794,664
26	(519) Coolants and Water	6,314,476	5,954,270
27	(520) Steam Expenses	5,135,530	5,314,694
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,042,372	4,835,623
31	(524) Miscellaneous Nuclear Power Expenses	17,674,123	18,221,793
32	(525) Rents	-245	71,895
33	TOTAL Operation (Enter Total of lines 24 thru 32)	95,904,831	97,926,703
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	3,932,753	4,131,491
36	(529) Maintenance of Structures	1,000,290	1,099,175
37	(530) Maintenance of Reactor Plant Equipment	7,653,682	6,381,307
38	(531) Maintenance of Electric Plant	7,253,620	8,151,275
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,149,571	2,333,212
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	21,989,916	22,096,460
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	117,894,747	120,023,163
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	/ /	End of 2013/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	37,156	29,652
63	(547) Fuel	6,810,024	2,448,213
64	(548) Generation Expenses	932	25,945
65	(549) Miscellaneous Other Power Generation Expenses	45,151	299,738
66	(550) Rents	6,360	6,363
67	TOTAL Operation (Enter Total of lines 62 thru 66)	6,899,623	2,809,911
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	4,985	281
70	(552) Maintenance of Structures	59,733	22,376
71	(553) Maintenance of Generating and Electric Plant	624,337	832,414
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	72,887	95,651
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	761,942	950,722
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	7,661,565	3,760,633
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	62,362,178	60,251,292
77	(556) System Control and Load Dispatching	1,057,930	1,176,092
78	(557) Other Expenses	755,704	804,000
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	64,175,812	62,231,384
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	400,029,989	364,846,422
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,103,029	1,190,625
84			
85	(561.1) Load Dispatch-Reliability	88,769	92,594
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	609,361	599,646
87	(561.3) Load Dispatch-Transmission Service and Scheduling	492,188	468,506
88	(561.4) Scheduling, System Control and Dispatch Services	945,419	939,847
89	(561.5) Reliability, Planning and Standards Development	794,317	753,063
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	268,080	167,553
94	(563) Overhead Lines Expenses	257,819	227,740
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	5,487,004	4,712,519
97	(566) Miscellaneous Transmission Expenses	4,258,377	4,071,024
98	(567) Rents	389,616	326,622
99	TOTAL Operation (Enter Total of lines 83 thru 98)	14,693,979	13,549,739
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	10,372	197,055
102	(569) Maintenance of Structures	10,407	13,873
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	624,537	635,165
108	(571) Maintenance of Overhead Lines	1,355,128	1,179,845
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	70,451	44,851
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,070,895	2,070,789
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	16,764,874	15,620,528

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	/ /	End of 2013/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	639,479	763,468
135	(581) Load Dispatching		
136	(582) Station Expenses	1,542,428	1,519,426
137	(583) Overhead Line Expenses	514,803	918,058
138	(584) Underground Line Expenses	286,444	305,425
139	(585) Street Lighting and Signal System Expenses	232,767	779,393
140	(586) Meter Expenses	1,833,242	1,872,417
141	(587) Customer Installations Expenses	478,669	468,839
142	(588) Miscellaneous Expenses	8,666,517	8,125,343
143	(589) Rents	125,920	455,327
144	TOTAL Operation (Enter Total of lines 134 thru 143)	14,320,269	15,207,696
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	53,042	-17,352
147	(591) Maintenance of Structures	1,973	
148	(592) Maintenance of Station Equipment	956,399	840,890
149	(593) Maintenance of Overhead Lines	4,884,281	3,861,001
150	(594) Maintenance of Underground Lines	625,186	421,292
151	(595) Maintenance of Line Transformers	45,314	23,032
152	(596) Maintenance of Street Lighting and Signal Systems	323,632	206,482
153	(597) Maintenance of Meters	207,385	201,113
154	(598) Maintenance of Miscellaneous Distribution Plant	322,296	259,929
155	TOTAL Maintenance (Total of lines 146 thru 154)	7,419,508	5,796,387
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	21,739,777	21,004,083
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision		
160	(902) Meter Reading Expenses	2,595,714	3,181,804
161	(903) Customer Records and Collection Expenses	12,602,838	12,713,597
162	(904) Uncollectible Accounts	2,097,500	3,086,580
163	(905) Miscellaneous Customer Accounts Expenses	306,428	289,223
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	17,602,480	19,271,204

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	5,845	32,976
169	(909) Informational and Instructional Expenses	193,825	170,191
170	(910) Miscellaneous Customer Service and Informational Expenses		
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	199,670	203,167
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	26,122,477	25,786,357
182	(921) Office Supplies and Expenses	6,033,993	5,424,843
183	(Less) (922) Administrative Expenses Transferred-Credit		
184	(923) Outside Services Employed	18,874,689	15,111,366
185	(924) Property Insurance	3,073,117	2,989,792
186	(925) Injuries and Damages	3,577,666	4,145,167
187	(926) Employee Pensions and Benefits	38,569,847	41,948,590
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	6,000,740	6,231,651
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	1,122,194	1,742,469
192	(930.2) Miscellaneous General Expenses	16,246,014	15,501,572
193	(931) Rents	648,862	512,779
194	TOTAL Operation (Enter Total of lines 181 thru 193)	120,269,599	119,394,586
195	Maintenance		
196	(935) Maintenance of General Plant	5,078,594	4,907,991
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	125,348,193	124,302,577
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	581,684,983	545,247,981

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	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Arizona Electric Power Cooperative	SF	1			
2	Arizona Public Service Company	SF	1			
3	Black Hills Power Inc	SF	1			
4	Cargill Power Markets, LLC	SF	1			
5	Citigroup Energy Inc.	SF	1			
6	City of Burbank California	SF	1			
7	Constellation Energy Commodities Group	SF	1			
8	EDF Trading North America, LLC	SF	1			
9	Four Peaks Energy Inc.	LU	1			
10	Freeport-McMoRan Copper & Gold Energy	LU	2			
11	Gila River Power, LLC	SF	1			
12	Gila River Power, LLC	OS	1			
13	Hatch Solar Energy Center 1 LLC	LU	1			
14	Iberdrola Renewables, LLC	SF	1			
	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)	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.
12,100				471,029		471,029	1
17,747				665,286		665,286	2
150				6,150		6,150	3
4,726				186,951		186,951	4
10,938				427,000		427,000	5
800				25,700		25,700	6
30,900				1,157,977		1,157,977	7
11,251				425,149		425,149	8
					1,573	1,573	9
603,991							10
22,428				863,554		863,554	11
					875	875	12
8,187				974,182	-162,221	811,961	13
1,310				56,265		56,265	14
2,103,782	67,412	19,273	1,536,000	58,970,901	1,855,277	62,362,178	

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	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Imperial Irrigation District	SF	1			
2	Los Alamos County	SF	1			
3	J. Aron & Company	SF	1			
4	J.P. Morgan Ventures Energy Corp	SF	1			
5	Los Angeles Department of Water and Po	SF	1			
6	Los Angeles Department of Water and Po	OS	1			
7	Macquarie Energy LLC	SF	1			
8	Morgan Stanley Capital Group, Inc.	SF	1			
9	NRG Solar Roadrunner LLC	LU	1			
10	PacifiCorp	SF	1			
11	Powerex Corp.	SF	1			
12	PPL Energy Plus, LLC	SF	1			
13	Public Service Company of New Mexico	SF	1			
14	Salt River Project Agricultural Improv	SF	1			
	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	/ /	End of 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,176				164,165		164,165	1
123				4,672		4,672	2
5,335				195,710		195,710	3
1,522				63,259		63,259	4
1,050				66,295		66,295	5
					12,852	12,852	6
1,506				44,586		44,586	7
106,196				3,415,376		3,415,376	8
52,836				6,627,171		6,627,171	9
33,832				1,090,900		1,090,900	10
7,702				417,832		417,832	11
400				13,200		13,200	12
8,344				283,578		283,578	13
117,251				4,531,990		4,531,990	14
2,103,782	67,412	19,273	1,536,000	58,970,901	1,855,277	62,362,178	

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	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Salt River Project Agricultural Improv	OS	1			
2	Sempra Generation	SF	1			
3	Shell Energy North America (US), L.P.	SF	2	40	40	40
4	Shell Energy North America (US), L.P.	OS	2			
5	Southern California Edison Co	SF	1			
6	Southwest Environmental Center	LU	1			
7	Southwestern Public Service Company	SF	1			
8	SunE EPE 1 LLC	LU	1			
9	SunE EPE 2 LLC	LU	1			
10	Tenaska Power Service Co	SF	1			
11	Transalta Energy Marketing (U.S.), Inc	SF	1			
12	Tri-State G & T Association, Inc.	SF	1			
13	Tri-State G & T Association, Inc.	OS	1			
14	Tucson Electric Power Company	SF	1			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					360	360	1
69,610				2,015,780		2,015,780	2
823,252			1,536,000	26,021,547		27,557,547	3
20,720					684,616	684,616	4
202				6,920		6,920	5
10				1,225		1,225	6
730				33,781		33,781	7
26,409				2,747,812		2,747,812	8
33,484				3,512,203		3,512,203	9
2,975				97,275		97,275	10
16,030				635,914		635,914	11
21,172				712,133		712,133	12
					375	375	13
19,407				945,755		945,755	14
2,103,782	67,412	19,273	1,536,000	58,970,901	1,855,277	62,362,178	

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	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tucson Electric Power Company	OS	1			
2	UNS Electric Inc	SF	1			
3	WAPA - Desert SouthWest	SF	1			
4	Arizona Electric Power Cooperative	SF	104	N/A	N/A	N/A
5	Arizona Public Service Company	SF	104	N/A	N/A	N/A
6	Eagle	SF	104	N/A	N/A	N/A
7	Farmington	SF	104	N/A	N/A	N/A
8	HGMA	SF	104	N/A	N/A	N/A
9	Los Alamos	SF	104	N/A	N/A	N/A
10	Panda Gila River	SF	104	N/A	N/A	N/A
11	Public Service Company of New Mexico	SF	104	N/A	N/A	N/A
12	Sempra Generation	SF	104	N/A	N/A	N/A
13	Salt River Project Agricultural Improv	SF	104	N/A	N/A	N/A
14	Tucson Electric Power Company	SF	104	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					660	660	1
75				2,625		2,625	2
30				810		810	3
34				992		992	4
300				8,581		8,581	5
5				64		64	6
17				805		805	7
15				729		729	8
10				453		453	9
65				1,004		1,004	10
279				10,614		10,614	11
44				2,019		2,019	12
146				8,036		8,036	13
331				14,275		14,275	14
2,103,782	67,412	19,273	1,536,000	58,970,901	1,855,277	62,362,178	

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	/ /	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tri-State G & T Association, Inc.	SF	104	N/A	N/A	N/A
2	Coral Power	EX	01			
3	Public Service Company of New Mexico	EX	01			
4	Salt River Project Agricultural Improv	EX	01			
5	Tri-State G&T Association, Inc.	EX	01			
6	Tucson Electric Power Company	EX	01			
7	Western Area Power Administration	EX	01			
8	Inadvertent					
9	NM Net Mtr PP	OS	16			
10	NM Net Mtr RECs	OS	33			
11	TX Non-Firm PP	OS	48			
12						
13						
14						
	Total					

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
260				11,572		11,572	1
	387						2
	32,245						3
		16,458					4
	16,610						5
	13,349						6
	317						7
	4,504	2,815					8
1,198					43,503	43,503	9
					1,267,309	1,267,309	10
171					5,375	5,375	11
							12
							13
							14
2,103,782	67,412	19,273	1,536,000	58,970,901	1,855,277	62,362,178	

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

1=WSPP Agreement - Rate Schedule FERC No. 6.

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

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

Schedule Page: 326 Line No.: 10 Column: g

The 603,991 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 Line No.: 12 Column: b

Spinning reserve purchases.

Schedule Page: 326 Line No.: 12 Column: l

Spinning reserve purchases.

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

Renewable Purchase Power Agreement between Hatch Solar Energy Center 1, LLC and El Paso Electric Company effective August 31, 2010, and continues for twenty-five years following the date of commercial operation in 2011.

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

Liquidated damages payment made by Hatch Solar Energy Center 1, LLC per Renewable Purchase Power Agreement between Hatch Solar Energy Center 1, LLC and El Paso Electric Company

Schedule Page: 326.1 Line No.: 6 Column: b

Spinning reserve purchases.

Schedule Page: 326.1 Line No.: 6 Column: l

Spinning reserve purchases.

Schedule Page: 326.1 Line No.: 9 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 in 2011.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

Schedule Page: 326.2 Line No.: 4 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.: 4 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.: 6 Column: b

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

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

Renewable Purchased Power Agreement between SunEdison 1 and El Paso Electric Company dated November 8, 2010, and continues for twenty-five years following the date of commercial operation in 2012.

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

Renewable Purchased Power Agreement between SunEdison 2 and El Paso Electric Company dated November 8, 2010, and continues for twenty-five years following the date of commercial operation in 2012.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

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

Spinning reserve purchases.

Schedule Page: 326.4 Line No.: 9 Column: c

New Mexico Rate No. 16.

Schedule Page: 326.4 Line No.: 9 Column: l

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

Schedule Page: 326.4 Line No.: 10 Column: c

New Mexico Rate No. 33.

Schedule Page: 326.4 Line No.: 10 Column: l

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

Schedule Page: 326.4 Line No.: 11 Column: c

Texas Rate No. 48.

Schedule Page: 326.4 Line No.: 11 Column: l

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

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	El Paso Electric Marketing	Public Service Company of New Mex	Comision Federal de Electricidad	NF
2	El Paso Electric Marketing	Arizona Public Service Company	Salt River Project	NF
3	El Paso Electric Marketing	Arizona Public Service Company	Salt River Project	SFP
4	Rio Grande Electric Co-Op	El Paso Electric Marketing	El Paso Electric Marketing	FNO
5	Arizona Electric Power Cooperative	Salt River Project	Arizona Public Service Company	NF
6	Arizona Electric Power Cooperative	Salt River Project	Arizona Public Service Company	LFP
7	Arizona Electric Power Cooperative	Arizona Public Service Company	Salt River Project	NF
8	Arizona Electric Power Cooperative	Arizona Public Service Company	Salt River Project	SFP
9	Constellation Energy	Salt River Project	Arizona Public Service Company	NF
10	Coral Power	Salt River Project	Salt River Project	LFP
11	Coral Power	Salt River Project	Arizona Public Service Company	NF
12	Coral Power	Salt River Project	Arizona Public Service Company	LFP
13	Coral Power	Arizona Public Service Company	Salt River Project	SFP
14	Eagle Energy Partners	Salt River Project	Salt River Project	NF
15	Eagle Energy Partners	Salt River Project	Salt River Project	NF
16	Eagle Energy Partners	Salt River Project	Salt River Project	LFP
17	Eagle Energy Partners	Salt River Project	Salt River Project	SFP
18	Eagle Energy Partners	Salt River Project	Arizona Public Service Company	NF
19	Eagle Energy Partners	Salt River Project	Arizona Public Service Company	NF
20	Eagle Energy Partners	Tucson Electric Power Company	Comision Federal de Electricidad	NF
21	Eagle Energy Partners	Arizona Public Service Company	Salt River Project	NF
22	Exelon Generation LLC	Salt River Project	Arizona Public Service Company	NF
23	Imperial Irrigation District	Salt River Project	Arizona Public Service Company	NF
24	JP Morgan Ventures	Salt River Project	Arizona Public Service Company	NF
25	JP Morgan Ventures	Arizona Public Service Company	Salt River Project	NF
26	Macquarie Cook Power	Salt River Project	Arizona Public Service Company	NF
27	Macquarie Cook Power	Arizona Public Service Company	Salt River Project	NF
28	Macquarie Cook Power	Arizona Public Service Company	Salt River Project	SFP
29	Morgan Stanley	Salt River Project	Arizona Public Service Company	NF
30	Morgan Stanley	Salt River Project	Arizona Public Service Company	SFP
31	Morgan Stanley	Arizona Public Service Company	Salt River Project	NF
32	Morgan Stanley	Arizona Public Service Company	Salt River Project	SFP
33	PacifiCorp Power Marketing	Arizona Public Service Company	Salt River Project	NF
34	PacifiCorp Power Marketing	Arizona Public Service Company	Salt River Project	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	/ /	End of 2013/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	Luna	Juarez, Mexico		10,500	10,500	1
01	Westwing	Palo Verde		545	545	2
01	Westwing	Palo Verde		8,080	8,080	3
01	EPE System	Coyote/Farmer	8	63,805	63,805	4
01	Palo Verde	Westwing		786	786	5
01	Palo Verde	Westwing	102	125,156	125,156	6
01	Westwing	Palo Verde		1,829	1,829	7
01	Westwing	Palo Verde		450	450	8
01	Palo Verde	Westwing		63,146	63,146	9
01	Palo Verde	Kyrene	133	154,704	154,704	10
01	Palo Verde	Westwing		2	2	11
01	Palo Verde	Westwing	125	199,735	199,735	12
01	Westwing	Palo Verde		57	57	13
01	Jojoba	Kyrene		1	1	14
01	Jojoba	Palo Verde		35,026	35,026	15
01	Jojoba	Palo Verde	200	694,248	694,248	16
01	Jojoba	Palo Verde		13,985	13,985	17
01	Jojoba	Westwing		120	120	18
01	Palo Verde	Westwing		13,423	13,423	19
01	Springerville	Juarez, Mexico		1	1	20
01	Westwing	Palo Verde		45	45	21
01	Palo Verde	Westwing		57,109	57,109	22
01	Palo Verde	Westwing				23
01	Palo Verde	Westwing		808	808	24
01	Westwing	Palo Verde		170	170	25
01	Palo Verde	Westwing		4,622	4,622	26
01	Westwing	Palo Verde		9,483	9,483	27
01	Westwing	Palo Verde		3,181	3,181	28
01	Palo Verde	Westwing		301,563	301,563	29
01	Palo Verde	Westwing		3,246	3,246	30
01	Westwing	Palo Verde		180	180	31
01	Westwing	Palo Verde		64	64	32
01	Westwing	Palo Verde		306	306	33
01	Westwing	Palo Verde		4,733	4,733	34
			1,662	**6,530,186**	**6,530,186**	

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
209,987	100,231		310,218	4
	736		736	5
498,244			498,244	6
	1,509		1,509	7
	425		425	8
	53,839		53,839	9
1,495,320			1,495,320	10
	131		131	11
612,876			612,876	12
	32		32	13
	1		1	14
	97,003		97,003	15
1,289,203	19,348		1,308,551	16
	28,033		28,033	17
	511		511	18
	12,149		12,149	19
	931		931	20
	215		215	21
	45,343		45,343	22
	11		11	23
	568		568	24
	170		170	25
	3,836		3,836	26
	8,256		8,256	27
	2,658		2,658	28
	282,407		282,407	29
	3,334		3,334	30
	1,631		1,631	31
	67		67	32
	284		284	33
	5,998		5,998	34
16,549,257	**6,000,350**	**0**	**22,549,607**	

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	Panda Gila River	Salt River Project	Salt River Project	NF
2	Panda Gila River	Salt River Project	Salt River Project	LFP
3	Panda Gila River	Salt River Project	Salt River Project	SFP
4	Panda Gila River	Salt River Project	Salt River Project	SFP
5	Panda Gila River	Salt River Project	Arizona Public Service Company	NF
6	Panda Gila River	Salt River Project	Arizona Public Service Company	SFP
7	Panda Gila River	Salt River Project	Salt River Project	NF
8	Panda Gila River	Salt River Project	Arizona Public Service Company	NF
9	Panda Gila River	Arizona Public Service Company	Salt River Project	NF
10	Powerex	Salt River Project	Arizona Public Service Company	LFP
11	Powerex	Salt River Project	Arizona Public Service Company	NF
12	Powerex	Salt River Project	Arizona Public Service Company	SFP
13	Powerex	Arizona Public Service Company	Salt River Project	NF
14	Powerex	Arizona Public Service Company	Salt River Project	SFP
15	PPM Energy, Inc	Salt River Project	Arizona Public Service Company	NF
16	PPM Energy, Inc	Arizona Public Service Company	Salt River Project	NF
17	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	NF
18	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	SFP
19	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	LFP
20	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	SFP
21	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	LFP
22	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	NF
23	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	SFP
24	Public Service Company of New Mexico	Southwestern Public Service Compa	Public Service Company of New Mex	NF
25	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	NF
26	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	SFP
27	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	SFP
28	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	LFP
29	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	NF
30	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	SFP
31	Public Service Company of New Mexico	Public Service Company of New Mex	Tucson Electric Power Company	SFP
32	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	NF
33	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	LFP
34	Public Service Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	SFP
	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	Jojoba	Palo Verde		10,161	10,161	1
01	Jojoba	Palo Verde	430	1,231,214	1,231,214	2
01	Jojoba	Palo Verde		420,067	420,067	3
01	Jojoba	Palo Verde	150	255,678	255,678	4
01	Jojoba	Westwing		9,637	9,637	5
01	Jojoba	Westwing		464	464	6
01	Palo Verde	Jojoba		180	180	7
01	Palo Verde	Westwing		39,702	39,702	8
01	Westwing	Palo Verde		100	100	9
01	Palo Verde	Westwing	32	69,136	69,136	10
01	Palo Verde	Westwing		66,027	66,027	11
01	Palo Verde	Westwing		493	493	12
01	Westwing	Palo Verde		6,895	6,895	13
01	Westwing	Palo Verde		1,385	1,385	14
01	Palo Verde	Westwing		713	713	15
01	Westwing	Palo Verde				16
01	Afton	Luna		162	162	17
01	Afton	Luna		62,535	62,535	18
01	Afton	Springerville	94	235,834	235,834	19
01	Afton	Springerville		1,582	1,582	20
01	Afton	Westmesa	141	320,940	320,940	21
01	Afton	Westmesa		159	159	22
01	Afton	Westmesa		114,471	114,471	23
01	Eddy	Westmesa		625	625	24
01	Las Cruces	Amrad		21	21	25
01	Las Cruces	Amrad		14,487	14,487	26
01	Luna	Afton		8	8	27
01	Luna	Springerville	60	58,651	58,651	28
01	Luna	Springerville		23	23	29
01	Luna	Springerville		7,061	7,061	30
01	Luna	Springerville	60	139,765	139,765	31
01	Westmesa	Amrad		6	6	32
01	Westmesa	Amrad	25	179,725	179,725	33
01	Westmesa	Amrad		15,951	15,951	34
			1,662	**6,530,186**	**6,530,186**	

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.
	22,749		22,749	1
2,603,149	34,174		2,637,323	2
	872,220		872,220	3
	357,167		357,167	4
	26,371		26,371	5
	1,499		1,499	6
	1,181		1,181	7
	52,603		52,603	8
	109		109	9
155,055	120		155,175	10
	66,749		66,749	11
	8,340		8,340	12
	6,748		6,748	13
	877		877	14
	936		936	15
	45		45	16
	993		993	17
	305,965		305,965	18
2,565,679			2,565,679	19
	25,687		25,687	20
2,355,743			2,355,743	21
	716		716	22
	592,513		592,513	23
	3,424		3,424	24
	114		114	25
	84,411		84,411	26
	44		44	27
1,694,002			1,694,002	28
	101		101	29
	5,227		5,227	30
	1,520,167		1,520,167	31
	27		27	32
727,276			727,276	33
	116,367		116,367	34
16,549,257	**6,000,350**	**0**	**22,549,607**	

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	/ /	End of 2013/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 Company of New Mexico	Public Service Company of New Mex	Public Service Company of New Mex	NF
2	Tenaska Power Services Company	Salt River Project	Arizona Public Service Company	NF
3	Tenaska Power Services Company	Salt River Project	Arizona Public Service Company	SFP
4	Transalta	Salt River Project	Arizona Public Service Company	NF
5	Tristate Generating and Transmission Coop	Tucson Electric Power Company	Public Service Company of New Mex	LFP
6	Tristate Generating and Transmission Coop	Public Service Company of New Mex	Public Service Company of New Mex	NF
7	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	NF
8	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	NF
9	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	LFP
10	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	SFP
11	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	LFP
12	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	NF
13	Tucson Electric Power	Public Service Company of New Mex	Tucson Electric Power Company	SFP
14	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	NF
15	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	SFP
16	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	NF
17	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	SFP
18	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	SFP
19	Tucson Electric Power	Salt River Project	Arizona Public Service Company	NF
20	Tucson Electric Power	Salt River Project	Arizona Public Service Company	SFP
21	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	NF
22	Tucson Electric Power	Tucson Electric Power Company	Tucson Electric Power Company	SFP
23	Tucson Electric Power	Arizona Public Service Company	Salt River Project	NF
24	UniSource Energy Services	Salt River Project	Arizona Public Service Company	NF
25	UniSource Energy Services	Salt River Project	Arizona Public Service Company	SFP
26	WestConnect	Salt River Project	Arizona Public Service Company	NF
27	WestConnect	Salt River Project	Arizona Public Service Company	NF
28	WestConnect	Arizona Public Service Company	Salt River Project	NF
29	Western Area Power Admin	Public Service Company of New Mex	Public Service Company of New Mex	LFP
30	Western Area Power Admin - DSW	Salt River Project	Arizona Public Service Company	NF
31	Western Area Power Admin - DSW	Salt River Project	Arizona Public Service Company	NF
32				
33				
34				
	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	/ /	End of 2013/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	Westmesa	Las Cruces		7	7	1
01	Palo Verde	Westwing		8,759	8,759	2
01	Palo Verde	Westwing		2,999	2,999	3
01	Palo Verde	Westwing		565	565	4
80	Springerville	Las Cruces/Orogrande	50	411,330	411,330	5
01	Westmesa	Las Cruces		136	136	6
01	Hidalgo	Greenlee				7
01	Luna	Greenlee		8,203	8,203	8
01	Luna	Greenlee	30	105,990	105,990	9
01	Luna	Greenlee		1,777	1,777	10
01	Luna	Springerville	10			11
01	Luna	Springerville		134	134	12
01	Luna	Springerville		10,211	10,211	13
01	Macho Springs	Greenlee		7,179	7,179	14
01	Macho Springs	Greenlee		667	667	15
01	Macho Springs	Springerville		666	666	16
01	Macho Springs	Springerville		8,866	8,866	17
01	Macho Springs	Springerville	10	81,521	81,521	18
01	Palo Verde	Westwing		450,416	450,416	19
01	Palo Verde	Westwing		4,572	4,572	20
01	Springerville	Greenlee		20,727	20,727	21
01	Springerville	Greenlee		254	254	22
01	Westwing	Palo Verde		140	140	23
01	Palo Verde	Westwing		349,292	349,292	24
01	Palo Verde	Westwing		1	1	25
01	Jojoba	Westwing		397	397	26
01	Palo Verde	Westwing		1,686	1,686	27
01	Westwing	Palo Verde		298	298	28
01	Westmesa	Holloman	2	7,892	7,892	29
01	Jojoba	Westwing		5	5	30
01	Palo Verde	Westwing		10,529	10,529	31
						32
						33
						34
			1,662	**6,530,186**	**6,530,186**	

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.
	54		54	1
	8,011		8,011	2
	3,361		3,361	3
	430		430	4
1,386,000			1,386,000	5
	742		742	6
	1,389		1,389	7
	48,023		48,023	8
872,732			872,732	9
	10,953		10,953	10
1,564			1,564	11
	1,481		1,481	12
	55,179		55,179	13
	43,115		43,115	14
	10,499		10,499	15
	9,505		9,505	16
	32,967		32,967	17
24,243	242,424		266,667	18
	361,080		361,080	19
	3,708		3,708	20
	104,103		104,103	21
	1,247		1,247	22
	441		441	23
	271,455		271,455	24
	52		52	25
	1,063		1,063	26
	1,647		1,647	27
	161		161	28
58,184			58,184	29
	15		15	30
	9,944		9,944	31
				32
				33
				34
16,549,257	**6,000,350**	**0**	**22,549,607**	

Schedule Page: 328 Line No.: 1 Column: a

El Paso Electric Marketing passed on transmission purchases to Comision Federal de Electricidad.

Schedule Page: 328 Line No.: 2 Column: a

El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

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

El Paso Electric Marketing is the marketing affiliate of El Paso Electric Company.

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

Network Integration Transmission Service expiration March 31, 2014.

Schedule Page: 328 Line No.: 6 Column: d

Firm transmission contracts of 17, 35 and 50 MW, expiration January 1, 2021. Service was partially redirected to hourly services.

Schedule Page: 328 Line No.: 10 Column: d

Firm transmission contract, expiration January 1, 2014.

Schedule Page: 328 Line No.: 12 Column: d

Firm transmission contracts of 25 and 100 MW, expiration January 1, 2021.

Schedule Page: 328 Line No.: 16 Column: d

Firm transmission contract, expiration October 1, 2013. Service was partially redirected to hourly services.

Schedule Page: 328.1 Line No.: 2 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 remained liable for the 200MW and was credited both the capacity and dollars in the following month upon EPE's receipt of payment from Eagle. Service was partially redirected to daily and hourly services.

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

Firm transmission contract, expiration January 1, 2014. Service was partially redirected to hourly services.

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

Firm transmission contract, expiration August 1, 2019. Service was partially redirected to daily and hourly services.

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

Firm transmission contracts of 111 and 30 MW, expiration January 1, 2019. Service was partially redirected to monthly and hourly services.

Schedule Page: 328.1 Line No.: 28 Column: d

Firm transmission contract, expiration January 1, 2020. Service was partially redirected to daily and hourly services.

Schedule Page: 328.1 Line No.: 33 Column: d

Firm transmission contract, expiration July 1, 2018.

Schedule Page: 328.2 Line No.: 5 Column: d

Firm transmission contract, expiration January 1, 2026.

Schedule Page: 328.2 Line No.: 9 Column: d

Firm transmission contract, expiration November 1, 2029.

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

Firm transmission contract, expiration November 1, 2029. Service was primarily redirected to monthly and daily services.

Schedule Page: 328.2 Line No.: 29 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	/ /	End of 2013/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Public Serv. Co. of NM	LFP	590,431	590,431	2,820,520			2,820,520
2	Public Serv. Co. of NM	OLF	93,084	93,084	575,373			575,373
3	Public Serv. Co. of NM	SFP	71,461	71,461		280,070		280,070
4	Public Serv. Co. of NM	NF	9,554	9,554		190,354		190,354
5	Public Serv. Co. of NM	AD					-52,954	-52,954
6	Salt River Project	OLF	164,016	164,016	1,633,250			1,633,250
7	Salt River Project	SFP	1,149	1,149		4,863		4,863
8	Salt River Project	NF	150	150		502		502
9	Tucson Electric Power	OLF	265,110	265,110				
10	Tucson Electric Power	SFP	1,845	1,845		20,602		20,602
11	Tucson Electric Power	NF	2,807	2,807		14,424		14,424
12								
13								
14								
15								
16								
	TOTAL		1,199,607	1,199,607	5,029,143	510,815	-52,954	5,487,004

Schedule Page: 332 Line No.: 1 Column: b
Contract expires June 30, 2017.
Schedule Page: 332 Line No.: 1 Column: c
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 1 Column: d
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 2 Column: b
Contract is an evergreen contract.
Schedule Page: 332 Line No.: 2 Column: c
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 2 Column: d
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 3 Column: c
Amounts shown based on actual energy flows and transmission reservations.
Schedule Page: 332 Line No.: 3 Column: d
Amounts shown based on actual energy flows and transmission reservations.
Schedule Page: 332 Line No.: 3 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.
Schedule Page: 332 Line No.: 4 Column: c
Amounts shown based on transmission reservations.
Schedule Page: 332 Line No.: 4 Column: d
Amounts shown based on transmission reservations.
Schedule Page: 332 Line No.: 4 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.
Schedule Page: 332 Line No.: 5 Column: g
Amounts shown represent 2011 portion of the FERC mandated refund for transmission service provided under PNM's Open Access Transmission Tariff.
Schedule Page: 332 Line No.: 6 Column: b
Contract expires concurrent with the ANPP Participation Agreement.
Schedule Page: 332 Line No.: 6 Column: c
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 6 Column: d
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 7 Column: c
Amounts shown based on transmission reservations.
Schedule Page: 332 Line No.: 7 Column: d
Amounts shown based on transmission reservations.
Schedule Page: 332 Line No.: 7 Column: f
Amounts shown include short term transmission reservations, related ancillary and losses.
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: 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.: 9 Column: c
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 9 Column: d
Amounts shown based on actual energy flows.
Schedule Page: 332 Line No.: 9 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.: 10 Column: c

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 10 Column: d

Amounts shown based on transmission reservations.

Schedule Page: 332 Line No.: 10 Column: f

Amounts shown include short term transmission reservations, related ancillary and losses.

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.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	332,555
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	737,636
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	21,314
6	Palo Verde General Expenses	11,555,383
7	Four Corners General Expenses	825,463
8	Palo Verde Transmission Line Cost	53,771
9	Director's Fees and Expenses	2,377,839
10	Economic Development	315,000
11	Travel	16,486
12	Collective Bargaining Agreement General Expenses	10,567
13		
14		
15		
16		
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46	TOTAL	16,246,014

Schedule Page: 335   Line No.: 10   Column: b

Primarily consists of contributions to promote economic development to (a) Borderplex Bi National Economic Alliance of $250,000; (b) Mesilla Valley Economic Development Alliance of $40,000; (c) Womens Economic Self Sufficiency of $15,000; and (d) ACCION New Mexico of $10,000.

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	/ /	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,682,899		7,682,899
2	Steam Production Plant	17,341,238	-6,544			17,334,694
3	Nuclear Production Plant	18,583,026	-1,219,391			17,363,635
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,255,384	416			2,255,800
7	Transmission Plant	6,657,184				6,657,184
8	Distribution Plant	18,791,093				18,791,093
9	Regional Transmission and Market Operation					
10	General Plant	6,623,529				6,623,529
11	Common Plant-Electric					
12	TOTAL	70,251,454	-1,225,519	7,682,899		76,708,834

B. Basis for Amortization Charges

Asset	Term	Basis	Amort Exp	Method
Computer Software	5 - 10 years	$69,660,808	$7,682,899	Straight Line

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
14							
15							
16							
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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		187,258	187,258	
3	FERC Annual Fee		607,922	607,922	
4					
5	Public Utility Commission of Texas				
6	Texas 2012 Rate Case Costs		1,754,326	1,754,326	2,335,230
7	Texas 2013 Fuel Reconciliation		296,795	296,795	
8	Texas General and Other		266,715	266,715	
9					
10	New Mexico Public Regulation Commission				
11	2010 FPPCAC Audit		581	581	432,575
12	New Mexico Procurement Plan		21,641	21,641	
13	New Mexico Energy Efficiency Filings		11,281	11,281	
14	New Mexico General and Other		45,552	45,552	
15					
16	Nuclear Regulatory Commission				
17	PVNGS Unit 1 Fees		884,618	884,618	
18	PVNGS Unit 2 Fees		876,931	876,931	
19	PVNGS Unit 3 Fees		936,208	936,208	
20					
21	Other		110,912	110,912	
22					
23					
24					
25					
26					
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43					
44					
45					
46	TOTAL		6,000,740	6,000,740	2,767,805

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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
		187,258					2
		607,922					3
							4
							5
		1,754,326		182.3	-1,754,326	580,904	6
		296,795					7
		266,715					8
							9
							10
		581	-53			432,522	11
		21,641					12
		11,281					13
		45,552					14
							15
							16
		884,618					17
		876,931					18
		936,208					19
							20
		110,912					21
							22
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							45
		6,000,740	-53		-1,754,326	1,013,426	46

Schedule Page: 350 Line No.: 6 Column: a

Represents Texas rate case costs related to Docket No. 40094 which the Company filed with the PUCT in February 2012. These costs are being amortized over two years beginning in May 2012.

Schedule Page: 350 Line No.: 7 Column: a

Represents Texas Fuel Reconciliation costs related to Docket No. 41852 which the Company filed with the PUCT in September 2013.

Schedule Page: 350 Line No.: 11 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	/ /	End of 2013/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	6,752,481		
4	Transmission	5,470,520		
5	Regional Market			
6	Distribution	8,469,098		
7	Customer Accounts	8,489,372		
8	Customer Service and Informational			
9	Sales			
10	Administrative and General	27,296,842		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	56,478,313		
12	Maintenance			
13	Production	4,903,894		
14	Transmission	776,105		
15	Regional Market			
16	Distribution	3,255,299		
17	Administrative and General	255,684		
18	TOTAL Maintenance (Total of lines 13 thru 17)	9,190,982		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,656,375		
21	Transmission (Enter Total of lines 4 and 14)	6,246,625		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,724,397		
24	Customer Accounts (Transcribe from line 7)	8,489,372		
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)	27,552,526		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	65,669,295	583,672	66,252,967
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	/ /	End of 2013/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

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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)	65,669,295	583,672	66,252,967
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	16,009,235	1,208,827	17,218,062
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	16,009,235	1,208,827	17,218,062
72	Plant Removal (By Utility Departments)			
73	Electric Plant		-105	-105
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)		-105	-105
77	Other Accounts (Specify, provide details in footnote):			
78	In-Kind Donations and Exp for Certain Civic, Political & Rel	171,157	-948	170,209
79	Prepayment and other	41,742	1,343	43,085
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	212,899	395	213,294
96	TOTAL SALARIES AND WAGES	81,891,429	1,792,789	83,684,218

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	/ /	End of 2013/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	8,354,189	MWh	802,002	6,032,181	MWh	1,326,457
2	Reactive Supply and Voltage	8,354,189	MWh	501,251	1,406,270	MWh	218,578
3	Regulation and Frequency Response				61,215	MWh	2,735
4	Energy Imbalance				10,500	MWh	-53,716
5	Operating Reserve - Spinning				61,215	MWh	11,004
6	Operating Reserve - Supplement				61,215	MWh	11,004
7	Other						
8	Total (Lines 1 thru 7)	16,708,378		1,303,253	7,632,596		1,516,062

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 1,226,175 MWh from hourly services, (of which 11,205 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 862,773 MWh from daily services, (of which 5,520 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 4,505 MWh from weekly services; 500,888 MWh from monthly services; and 3,437,840 MWh from yearly contracts, (of which 61,215 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

$138,034 pertains to hourly services (of which $1,076 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $96,945 pertains to daily services (of which $759 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $551 pertains to weekly services. $84,884 pertains to monthly services and $1,006,043 pertains to yearly contracts, (of which $7,125 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 203,037 MWh from hourly services (of which 3,300 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 38,982 MWh from daily services (of which 4,800 MWh were sold to El Paso Electric Marketing, an affiliate of El Paso Electric Company); 211,397 MWh from monthly services; and 952,854 MWh from yearly contracts, (of which 61,215 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

$15,197 pertains to hourly services (of which $198 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $4,608 pertains to daily services (of which $435 pertains to El Paso Electric Marketing, an affiliate of El Paso Electric Company). $32,990 pertains to monthly services and $165,783 pertains to yearly contracts, (of which $4,463 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.: 4 Column: e

All units pertain to El Paso Electric Marketing, an affiliate of El Paso Electric Company.

Schedule Page: 398 Line No.: 4 Column: g

All from sales to El Paso Electric Marketing, an affiliate 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
El Paso Electric Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2013/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	1,177	3	1900		5	1,310	50	74	
2	February	1,012	19	1900		5	1,318	50	66	
3	March	971	14	2000		7	1,283	50	101	
4	Total for Quarter 1	3,160				17	3,911	150	241	
5	April	1,270	30	1600		9	1,303	50	81	
6	May	1,473	23	1500		8	1,314	50	70	
7	June	1,742	27	1600		11	1,314	50	70	
8	Total for Quarter 2	4,485				28	3,931	150	221	
9	July	1,667	11	1400		12	1,314	50	70	
10	August	1,665	9	1500		12	1,314	50	70	
11	September	1,531	5	1600		13	1,312	50	72	
12	Total for Quarter 3	4,863				37	3,940	150	212	
13	October	1,254	2	1600		7	640	50	114	
14	November	1,061	25	2000		3	673	50	81	
15	December	1,115	12	1900		4	683	50	71	
16	Total for Quarter 4	3,430				14	1,996	150	266	
17	Total Year to Date/Year	15,938				96	13,778	600	940	

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)	7,746,396
3	Steam	4,157,730			
4	Nuclear	4,966,233	23	Requirements Sales for Resale (See instruction 4, page 311.)	61,232
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,076,613
7	Other	164,810			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	9,288,773	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	16,244
10	Purchases	2,103,782	27	Total Energy Losses	540,209
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	11,440,694
12	Received	67,412			
13	Delivered	19,273			
14	Net Exchanges (Line 12 minus line 13)	48,139			
15	Transmission For Other (Wheeling)				
16	Received	6,530,186			
17	Delivered	6,530,186			
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)	11,440,694			

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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	885,255	225,474	1,177	3	1900
30	February	817,198	263,075	1,012	19	1900
31	March	886,211	301,569	971	14	2000
32	April	781,751	166,704	1,270	30	1600
33	May	1,013,621	299,842	1,473	23	1500
34	June	1,084,171	209,788	1,742	27	1600
35	July	1,141,823	280,320	1,667	11	1400
36	August	1,174,402	284,983	1,665	19	1500
37	September	1,061,546	307,613	1,531	5	1600
38	October	863,868	230,265	1,254	2	1600
39	November	821,605	233,135	1,061	25	2000
40	December	909,243	273,845	1,115	12	1900
41	TOTAL	11,440,694	3,076,613			

Schedule Page: 401 Line No.: 10 Column: b
Includes 603,991 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 603,991 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 603,991 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.: 28 Column: b
Includes 603,991 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.: 29 Column: b
Includes 42,392 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 29 Column: c
Includes 42,392 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 30 Column: b
Includes 37,920 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 30 Column: c
Includes 37,920 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 31 Column: b
Includes 32,358 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 31 Column: c
Includes 33,879 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 32 Column: b
Includes 45,699 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 32 Column: c
Includes 44,178 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 33 Column: b
Includes 48,622 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 33 Column: c
Includes 48,622 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 34 Column: b
Includes 51,200 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 34 Column: c
Includes 51,200 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 35 Column: b
Includes 59,627 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 35 Column: c
Includes 59,627 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 36 Column: b
Includes 64,392 MWhs related to sales to Freeport related to the Company's Power Purchase

and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 36 Column: c

Includes 64,392 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 37 Column: b

Includes 65,297 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 37 Column: c

Includes 65,297 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 38 Column: b

Includes 62,308 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 38 Column: c

Includes 62,308 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 39 Column: b

Includes 35,706 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 39 Column: c

Includes 35,706 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 40 Column: b

Includes 58,470 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport dated December 16, 2005.

Schedule Page: 401 Line No.: 40 Column: c

Includes 58,470 MWhs related to sales to Freeport related to the Company's Power Purchase and Sales Agreement with Freeport 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	/ /	End of 2013/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: *Rio Grande Unit 9* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Indoor and Outdoor			Outdoor		
3	Year Originally Constructed	1929			2013		
4	Year Last Unit was Installed	1972			2013		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	266.00			132.00		
6	Net Peak Demand on Plant - MW (60 minutes)	195			105		
7	Plant Hours Connected to Load	7482			1930		
8	Net Continuous Plant Capability (Megawatts)	229			86		
9	When Not Limited by Condenser Water	238			93		
10	When Limited by Condenser Water	229			86		
11	Average Number of Employees	52			0		
12	Net Generation, Exclusive of Plant Use - KWh	609198000			126537000		
13	Cost of Plant: Land and Land Rights	100946			0		
14	Structures and Improvements	5358541			14315		
15	Equipment Costs	52664167			94123567		
16	Asset Retirement Costs	76983			0		
17	Total Cost	58200637			94137882		
18	Cost per KW of Installed Capacity (line 17/5) Including	218.7994			713.1658		
19	Production Expenses: Oper, Supv, & Engr	623253			4209		
20	Fuel	30872478			4110822		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	1387146			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	156727			0		
26	Misc Steam (or Nuclear) Power Expenses	1521470			9607		
27	Rents	2727			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	755565			1045		
30	Maintenance of Structures	496521			12240		
31	Maintenance of Boiler (or reactor) Plant	2194445			299910		
32	Maintenance of Electric Plant	2418769			22757		
33	Maintenance of Misc Steam (or Nuclear) Plant	748950			0		
34	Total Production Expenses	41178051			4460590		
35	Expenses per Net KWh	0.0676			0.0353		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Mcf	BBL		Mcf	BBL	
38	Quantity (Units) of Fuel Burned	7039876	0	0	1099767	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1024000	0	0	1023300	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.385	0.000	0.000	3.738	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.385	0.000	0.000	3.738	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.283	0.000	0.000	3.653	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.051	0.000	0.000	0.032	0.000	0.000
44	Average BTU per KWh Net Generation	11833.000	0.000	0.000	8894.000	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	/ /	End of 2013/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: *Newman* (d)			Plant Name: *Four Corners* (e)			Plant Name: *Copper* (f)			Line No.
Steam						Gas Turbine			1
Indoor and Outdoor						Outdoor			2
1959						1979			3
2011						1980			4
889.00			0.00			79.00			5
650			0			64			6
8583			0			987			7
732			0			62			8
751			0			62			9
732			0			62			10
77			0			12			11
2912815000			635717000			37561000			12
181900			8623			10000			13
45356571			3410390			727599			14
360964673			88887238			14935731			15
-325470			460189			15479			16
406177674			92766440			15688809			17
456.8928			0			198.5925			18
1169388			174636			0			19
126457165			12507912			2699202			20
0			0			0			21
921364			1383288			0			22
0			0			0			23
0			0			0			24
2774796			125384			0			25
2961000			1006983			57263			26
467325			829807			0			27
35944			0			0			28
731315			224198			3940			29
667368			86069			47494			30
4501989			2822992			324427			31
5814125			579994			42201			32
1077617			627259			0			33
147579396			20368522			3174527			34
0.0507			0.0320			0.0845			35
Gas	Oil		Coal	Gas		Gas	Oil		36
Mcf	BBL		Ton	Mcf		Mcf	BBL		37
26353242	0	0	367011	27151	0	619788	0	0	38
1020000	0	0	17313863	1010000	0	1019000	0	0	39
4.799	0.000	0.000	33.600	6.499	0.000	4.355	0.000	0.000	40
4.799	0.000	0.000	33.600	6.499	0.000	4.355	0.000	0.000	41
4.704	0.000	0.000	1.941	6.435	0.000	4.274	0.000	0.000	42
0.043	0.000	0.000	0.020	0.000	0.000	0.072	0.000	0.000	43
9228.000	0.000	0.000	10039.000	0.000	0.000	16814.000	0.000	0.000	44

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	/ /	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Palo Verde* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	4966233000			0		
13	Cost of Plant: Land and Land Rights	2347703			0		
14	Structures and Improvements	483327506			0		
15	Equipment Costs	1238530579			0		
16	Asset Retirement Costs	-42229190			0		
17	Total Cost	1681976598			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	12557865			0		
20	Fuel	49180710			0		
21	Coolants and Water (Nuclear Plants Only)	6314476			0		
22	Steam Expenses	5135530			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	5042372			0		
26	Misc Steam (or Nuclear) Power Expenses	17674123			0		
27	Rents	-245			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	3932753			0		
30	Maintenance of Structures	1000290			0		
31	Maintenance of Boiler (or reactor) Plant	7653682			0		
32	Maintenance of Electric Plant	7253620			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	2149571			0		
34	Total Production Expenses	117894747			0		
35	Expenses per Net KWh	0.0237			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Nuclear					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MMbtu					
38	Quantity (Units) of Fuel Burned	51149063	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.962	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.962	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.962	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.010	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	10299.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
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0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 403 Line No.: 1 Column: e

Jointly owned plant.

Schedule Page: 403 Line No.: 2 Column: e

Data on lines 2-11 for total plant to be reported by the Operating Agent, Arizona Public Service Company.

Schedule Page: 402 Line No.: 11 Column: c

Average number of employees included in the number for Rio Grande Plant.

Schedule Page: 403 Line No.: 20 Column: e

Excludes $1,171,896 related to the amortization of final coal reclamation costs.

Schedule Page: 402.1 Line No.: 1 Column: b

Jointly owned plant.

Schedule Page: 402.1 Line No.: 2 Column: b

Data on lines 2-11 for total plant to be reported by the Operating Agent, Arizona Public Service Company.

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	/ /	End of 2013/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	Solar Plants					
2	Newman PV System	2009	0.06		131	145,666
3	Rio Grande PV System	2009	0.06		128	168,882
4	Wrangler CPV System	2011	0.05		123	418,730
5	Stanton PV System	2012	0.03		68	273,687
6	El Paso Community College PV System	2012	0.02		32	97,020
7	Van Horn PV System	2013	0.02		10	99,675
8	Total Solar		0.24		492	1,203,660
9						
10						
11						
12						
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46						

Name of Respondent El Paso Electric Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2013/Q4

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
8,983,900						2
9,266,767						3
8,723,542			5,629			4
8,552,719						5
6,468,000			1,180			6
5,863,235						7
8,267,300			6,809			8
						9
						10
						11
						12
						13
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						44
						45
						46

Schedule Page: 410 Line No.: 2 Column: f

Includes credits of $393,368 recovered through the Volunteer Renewable Energy (VRE) Program.

Schedule Page: 410 Line No.: 2 Column: g

Excludes credits of $393,368 recovered through the VRE Program.

Schedule Page: 410 Line No.: 3 Column: f

Includes credits of $387,124 recovered through the VRE Program.

Schedule Page: 410 Line No.: 3 Column: g

Excludes credits of $387,124 recovered through the VRE Program.

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	/ /	End of 2013/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)	79.93	125.45	1
9	Diablo	Luna	345.00	345.00	(2)	85.66		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)	441.47	54.40	1
15	Various 69kV Lines		69.00	69.00	(1),(2)	204.65	21.55	1
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,357.29	431.20	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) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
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	11,736,151	12,666,189					4
795 ACSR	423,552	5,155,744	5,579,296					5
795 ACSR	811,653	9,879,964	10,691,617					6
795 ACSR	86,513	1,415,934	1,502,447					7
954 ACSR/T2	2,845,159	17,240,346	20,085,505					8
954 ACSR	1,114,625	12,378,266	13,492,891					9
954 ACSR	19,320	6,752,795	6,772,115					10
954 ACSR	154,575	54,028,439	54,183,014					11
								12
								13
Various	4,365,352	68,260,577	72,625,929					14
Various	309,717	12,410,817	12,720,534					15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	13,824,221	211,706,224	225,530,445					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.: 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	/ /	End of 2013/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	To		Type	Average Number per Miles	Present	Ultimate
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	Santa Teresa	Montoya	7.37	1	15.00	1	1
2							
3							
4							
5							
6							
7							
8							
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37							
38							
39							
40							
41							
42							
43							
44	TOTAL		7.37		15.00	1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
954	ACSR	Vertical	115	2,379,015	8,355,811	5,175,297		15,910,123	1
									2
									3
									4
									5
									6
									7
									8
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									41
									42
									43
				2,379,015	8,355,811	5,175,297		15,910,123	44

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	/ /	End of 2013/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	Airport New Mexico	Dist. UA	115.00	23.90	
5	Alamo Lower Valley	Dist. UA	69.00	23.90	
6	Altura El Paso	Dist. UA	13.80	4.16	
7	Americas El Paso	Dist. UA	69.00	13.80	
8	Amrad Oro Grande, NM	Trans. UA	345.00	115.00	13.00
9	Amrad Oro Grande, NM	Dist. UA	115.00	24.90	
10	Anthony Anthony, NM	Dist. UA	115.00	24.90	
11	Apollo New Mexico	Dist. UA	69.00	2.40	
12	Arroyo Las Cruces, NM	Trans. UA	345.00	345.00	
13	Arroyo Las Cruces, NM	Trans. UA	345.00	115.00	13.80
14	Arroyo Las Cruces, NM	Dist. UA	115.00	23.90	
15	Arroyo Las Cruces, NM	Dist. UA	115.00	23.90	
16	Ascarate El Paso	Dist. UA	115.00	69.00	13.80
17	Ascarate El Paso	Dist. UA	115.00	69.00	
18	Ascarate El Paso	Dist. UA	69.00	13.80	
19	Ascarate El Paso	Dist. UA	69.00	4.16	
20	Austin El Paso	Dist. UA	115.00	13.80	
21	Austin El Paso	Dist. UA	69.00	4.16	
22	Biggs El Paso	Dist. UA	115.00		
23	Border Steel El Paso	Dist. UA	115.00	13.80	
24	Butterfield El Paso	Dist. UA	115.00	13.80	
25	Caliente El Paso	Trans. UA	345.00	115.00	13.80
26	Caliente El Paso	Trans. UA	115.00	13.80	
27	Chaparral Chaparral, NM	Dist. UA	115.00	13.80	
28	Clint Lower Valley	Dist. UA	69.00	13.80	
29	Clint Lower Valley	Dist. UA	69.00	4.16	
30	Copper El Paso	Dist. UA	13.80	115.00	
31	Copper El Paso	Dist. UA	115.00	13.80	
32	Copper El Paso	Dist. UA	13.80	45.80	
33	Copper El Paso	Dist. UA	13.80	0.48	
34	Cox New Mexico	Trans. UA	115.00	69.00	
35	Coyote Lower Valley	Dist. UA	115.00	13.80	
36	Cromo El Paso	Dist. UA	115.00	13.80	
37	Dallas El Paso	Dist. UA	69.00	13.80	
38	Dallas El Paso	Dist. UA	69.00	13.80	
39	Dallas El Paso	Dist. UA	13.80	4.16	
40	Diablo Sunland Park, NM	Trans. UA	345.00	115.00	13.80

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
30	1					4
30	1					5
13	2					6
30	1					7
261	1					8
8	1					9
60	2					10
30	1					11
308	1					12
400	2					13
30	1					14
30	1	1				15
100	1					16
100	1					17
60	2					18
10	1					19
80	2					20
10	3					21
						22
70	2					23
60	2					24
400	2					25
30	3					26
60	2					27
8	1					28
3	3					29
75	1					30
30	1					31
2	1					32
1	1					33
12	1					34
13	1					35
60	2					36
20	1					37
20	1					38
5	2					39
600	3					40

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	Durazno El Paso	Dist. UA	115.00	13.80	
2	Dyer El Paso	Dist. UA	69.00	13.80	
3	Dyer El Paso	Dist. UA	115.00	69.00	
4	EMRLD New Mexico	Dist. UA	115.00	13.80	
5	Farah El Paso	Dist. UA	69.00	13.80	
6	Felipe El Paso	Dist. UA	69.00	23.90	
7	Fort Bliss El Paso	Dist. UA	115.00	13.80	
8	Global Reach El Paso	Dist. UA	115.00	13.80	
9	Hatch New Mexico	Dist. UA	115.00	24.90	
10	Hatch New Mexico	Dist. UA	23.90	4.16	
11	Lane Lower Valley	Dist. UA	115.00	69.00	
12	Lane Lower Valley	Dist. UA	115.00	13.80	
13	Las Cruces Las Cruces, NM	Dist. UA	115.00	24.00	
14	Las Cruces Las Cruces, NM	Dist. UA	23.90	4.16	
15	Las Cruces Las Cruces, NM	Dist. UA	115.00	23.90	
16	Leo El Paso	Dist. UA	69.00	13.80	
17	Leo El Paso	Dist UA	13.80	4.16	
18	Mann Lower Valley	Dist. UA	69.00	13.80	
19	Mann Lower Valley	Dist. UA	69.00	13.80	
20	Mesa El Paso	Dist. UA	115.00	13.80	
21	Milagro El Paso	Dist. UA	115.00	69.00	
22	Milagro El Paso	Dist. UA	115.00	13.80	
23	Montoya Upper Valley, NM	Dist. UA	115.00	23.90	
24	Montwood El Paso	Dist. UA	115.00	23.90	
25	Newman T-1	Trans. UA	345.00	115.00	13.80
26	Newman T-2	Trans. UA	13.80	115.00	
27	Newman T-3	Dist. UA	115.00	2.40	
28	Newman T-4	Dist. UA	13.80	2.40	
29	Newman T-5	Dist. UA	13.80	2.40	
30	Newman T-6	Trans. UA	13.80	115.00	
31	Newman T-7	Dist. UA	13.80	2.40	
32	Newman T-8	Trans. UA	13.80	115.00	
33	Newman T-9	Trans. UA	13.80	115.00	
34	Newman T-10	Dist. UA	13.80	4.16	
35	Newman T-11	Trans. UA	13.80	115.00	
36	Newman T-12	Dist. UA	115.00	4.16	
37	Newman T-13	Trans. UA	13.80	115.00	
38	Newman T-14	Trans. UA	13.80	115.00	
39	Newman T-15	Trans. UA	13.80	115.00	
40	Newman T-16	Trans. UA	13.80	115.00	

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa)	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)	
30	1					1
50	2					2
100	1					3
13	1					4
30	1					5
30	1					6
50	2					7
30	1					8
30	1					9
2	1					10
100	1					11
30	1					12
40	2					13
6	1					14
120	2					15
20	1					16
5	2					17
30	1					18
24	1					19
60	2					20
100	1					21
90	3					22
130	3					23
30	1	1				24
230	1					25
112	1					26
6	1					27
5	1					28
10	1					29
112	1					30
10	1					31
112	1					32
112	1					33
10	1					34
112	1					35
20	1					36
125	1					37
175	1					38
117	1					39
117	1					40

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	Newman T-17	Dist. UA	13.80	4.16	
2	Newman T-18	Dist. UA	13.80	4.16	
3	Picante T-1	Trans. UA	345.00	115.00	
4	Santa Teresa T-2	Trans. UA	115.00	24.90	
5	Patriot	Dist. UA	115.00	13.80	
6	Phelps Dodge El Paso	Dist. UA	69.00	13.80	
7	Phelps Dodge El Paso	Dist. UA	13.80	2.30	
8	Phelps Dodge El Paso	Dist. UA	13.80	4.16	
9	Pellicano El Paso	Dist. UA	115.00	23.90	
10	Picacho New Mexico	Dist. UA	115.00	23.90	
11	Redeye New Mexico	Dist. UA	115.00	13.80	
12	Rio Grande Sunland Park, New Mexico	Dist. UA	17.20	115.00	
13	Rio Grande Sunland Park, New Mexico	Dist. UA	115.00	69.00	
14	Rio Grande Sunland Park, New Mexico	Dist. UA	69.00	2.40	
15	Rio Grande Sunland Park, New Mexico	Dist. UA	13.80	4.16	
16	Rio Grande Sunland Park, New Mexico	Trans. UA	18.00	4.16	
17	Rio Grande Sunland Park, New Mexico	Trans. UA	13.80	69.00	
18	Rio Grande Sunland Park, New Mexico	Trans. UA	14.40	4.16	
19	Rio Grande Sunland Park, New Mexico	Dist. UA	69.00	14.40	
20	Rio Grande Sunland Park, New Mexico	Trans. UA	13.80	2.40	
21	Rio Grande Sunland Park, New Mexico	Dist. UA	14.40	2.40	
22	Rio Grande Sunland Park, New Mexico	Dist. UA	13.80	115.00	
23	Rio Grande Sunland Park, New Mexico	Dist. UA	13.80	4.16	
24	Ripley El Paso	Dist. UA	115.00	13.80	
25	Pendale El Paso	Dist. UA	115.00	13.80	
26	Salopek Las Cruces, NM	Dist. UA	115.00	24.90	
27	Santa Fe El Paso	Dist. UA	69.00	13.80	
28	Santa Fe El Paso	Dist. UA	13.80	4.16	
29	Santa Teresa Santa Teresa	Dist. UA	115.00	24.90	
30	Scotsdale El Paso	Dist. UA	115.00	69.00	
31	Scotsdale El Paso	Dist. UA	115.00	13.80	
32	Shearman El Paso	Dist. UA	115.00	13.80	
33	Socorro Lower Valley	Dist. UA	69.00	13.80	
34	Sol El Paso	Dist. UA	115.00	13.80	
35	Sparks El Paso	Dist. UA	115.00	13.80	
36	Sunset El Paso	Dist. UA	69.00	13.80	
37	Sunset El Paso	Dist. UA	69.00	4.16	
38	Sunset North El Paso	Dist. UA	115.00	13.80	
39	Sunset North El Paso	Dist. UA	115.00	69.00	
40	Thorn El Paso	Dist. UA	115.00	13.80	

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.
17	1					1
17	1					2
220	1					3
30	1					4
12	1					5
10	3					6
10	2					7
5	1					8
30	1					9
50	1					10
13	1					11
348	1	1				12
200	2					13
11	1					14
10	1					15
14	1					16
50	1					17
4	1					18
20	1					19
3	1					20
8	2					21
132	1					22
6	1					23
30	1					24
30	1					25
78	3					26
25	1					27
11	3					28
60	2					29
100	1					30
55	2					31
30	1					32
30	1					33
60	2					34
30	1					35
30	2					36
10	3					37
60	2					38
70	1					39
60	2					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	/ /	End of 2013/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	Viscount El Paso	Dist. UA	69.00	13.80	
2	Vista El Paso	Dist. UA	115.00	13.80	
3	White Sands New Mexico	Dist. UA	115.00	13.80	
4	Wrangler El Paso	Dist. UA	115.00	13.80	
5	Sparks El Paso	Dist. UA	115.00	69.00	
6	Rio Bosque	Dist. UA	115.00	13.80	
7	Leo Temp	Dist. UA	69.00	13.80	
8	Transmountain Temp	Dist. UA	115.00	24.90	
9	5,000 to 10,000 kVA				
10					
11	Clint Lower Valley	Dist. UA	69.00	13.80	
12	Clint Lower Valley	Dist. UA	69.00	4.16	
13	Darbyshire El Paso	Dist. UA	69.00	13.80	
14	Diana El Paso	Dist. UA	13.80	4.16	
15	Farmer Van Horn	Dist. UA	69.00	23.90	
16	Five Points El Paso	Dist. UA	13.80	4.16	
17	Horizon Horizon	Dist. UA	69.00	13.80	
18	Locust New Mexico	Dist. UA	23.90	4.16	
19	Mar New Mexico	Dist. UA	115.00	4.16	
20	Mar New Mexico	Dist. UA	24.90	4.16	
21	McGregor New Mexico	Dist. UA	69.00	13.80	
22	Proler Proler	Dist. UA	69.00	2.40	
23	S.P. Pipeline El Paso	Dist. UA	13.80	2.40	
24	Sierra Blanca Sierra Blanca	Dist. UA	69.00	24.00	
25	Sierra Blanca Sierra Blanca	Dist. UA	23.90	4.16	
26	Tobin El Paso	Dist. UA	13.80	4.16	
27	Valley Lower Valley	Dist. UA	69.00	13.80	
28	Durazno El Paso	Dist. UA	69.00	13.80	
29	1,000 to 5,000 kVA				
30					
31	Alameda Las Cruces, NM	Dist. UA	23.90	4.16	
32	Beaumont El Paso	Dist. UA	13.80	4.16	
33	Cadwallader El Paso	Dist. UA	13.80	4.16	
34	Canutillo Upper Valley	Dist. UA	23.90	4.16	
35	Cielo El Paso	Dist. UA	13.80	4.16	
36	Cinecue El Paso	Dist. UA	13.80	4.16	
37	Clardy El Paso	Dist. UA	13.80	4.16	
38	Coronado El Paso	Dist. UA	13.80	4.16	
39	Cotton El Paso	Dist. UA	13.80	4.16	
40	East El Paso	Dist. UA	13.80	4.16	

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
60	2					2
30	1					3
50	1					4
100	1					5
30	1					6
16	1					7
20	1					8
						9
						10
8	1					11
1	1					12
6	3					13
6	7					14
10	1					15
6	3					16
30	1					17
6	1					18
10	1					19
3	1					20
8	1					21
6	1					22
6	1					23
8	3					24
1	1					25
6	2					26
8	1					27
8	1					28
						29
						30
3	1					31
3	1					32
3	1					33
2	1					34
3	2					35
3	1					36
3	2					37
3	1					38
3	2					39
3	2					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	/ /	End of 2013/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	Fabens Lower Valley	Dist. UA	69.00	4.16	
2	Franklin El Paso	Dist. UA	13.80	4.16	
3	Fresno El Paso	Dist. UA	13.80	4.16	
4	Frontera Upper Valley	Dist. UA	13.80	4.16	
5	Grace El Paso	Dist. UA	13.80	4.16	
6	Griggs Upper Valley	Dist. UA	23.90	4.16	
7	Hacienda El Paso	Dist. UA	13.80	4.16	
8	Hanes New Mexico	Dist. UA	23.90	4.16	
9	Hueco El Paso	Dist. UA	69.00	23.90	
10	Hueco El Paso	Dist. UA	23.90	0.48	
11	Kemp El Paso	Dist. UA	13.80	4.16	
12	Latta El Paso	Dist. UA	13.80	4.16	
13	Lomaland El Paso	Dist. UA	13.80	4.16	
14	McClure Las Cruces, NM	Dist. UA	23.90	4.16	
15	Melendres Las Cruces, NM	Dist. UA	23.90	4.16	
16	Mesilla Park Mesilla Park, NM	Dist. UA	23.90	4.16	
17	Mission El Paso	Dist. UA	13.80	4.16	
18	Missouri Las Cruces, NM	Dist. UA	23.90	4.16	
19	Morningside El Paso	Dist. UA	13.80	4.16	
20	Mountain El Paso	Dist. UA	13.80	4.16	
21	Mulberry Upper Valley	Dist. UA	13.80	4.16	
22	Newell Newell	Dist. UA	13.80	2.40	
23	Newtex Upper Valley	Dist. UA	23.90	4.16	
24	Octavia El Paso	Dist. UA	13.80	4.16	
25	Parkdale El Paso	Dist. UA	13.80	4.16	
26	Prison El Paso	Dist. UA	23.90	2.40	
27	Railroad El Paso	Dist. UA	13.80	2.40	
28	Ranchland El Paso	Dist. UA	13.80	4.16	
29	Range New Mexico	Dist. UA	24.90	13.20	
30	River Upper Valley	Dist. UA	13.80	4.16	
31	Rosedale El Paso	Dist. UA	13.80	4.16	
32	Sierra Blanca Sierra Blanca	Dist. UA	69.00	23.90	
33	Sierra Blanca Sierra Blanca	Dist. UA	23.90	4.16	
34	Summit El Paso	Dist. UA	13.80	4.16	
35	UTEP El Paso	Dist. UA	13.80	4.16	
36	Van Horn Van Horn	Dist. UA	23.90	4.16	
37	Vinton New Mexico	Dist. UA	23.90	4.16	
38	Water Trtmnt El Paso	Dist. UA	13.80	2.40	
39	Westside Las Cruces, NM	Dist. UA	23.90	4.16	
40	White Upper Valley	Dist. UA	13.80	4.16	

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.
3	3					1
2	3					2
2	1					3
2	1					4
2	1					5
1	1					6
5	1					7
5	1					8
3	3					9
	1					10
2	1					11
2	1					12
4	2					13
2	1					14
3	3					15
2	1					16
5	1					17
3	1					18
3	2					19
2	1					20
3	2					21
3	1					22
3	2					23
2	1					24
3	2					25
3	1					26
2	3					27
4	2					28
8	3					29
1	1					30
2	1					31
18	1					32
1	1					33
4	2					34
4	1					35
3	4					36
3	1					37
4	1					38
3	1					39
2	1					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	/ /	End of 2013/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	Ysleta El Paso	Dist. UA	13.80	4.16	
2					
3	300 to 999 kVA				
4					
5	Chevron Pipeline New Mexico	Dist. UA	23.90	2.40	
6	Dona Ana New Mexico	Dist. UA	23.90	4.16	
7	Fort Hancock Hudspeth County	Dist. UA	24.90	4.16	
8	La Mesa New Mexico	Dist. UA	23.90	4.16	
9	La Posta New Mexico	Dist. UA	23.90	4.16	
10	Tornillo Lower Valley	Dist. UA	24.40	4.16	
11	Wilson El Paso	Dist. UA	13.80	2.40	
12					
13	300 kVA (Distribution Racks)				
14					
15	Acala Hudspeth County	Dist. UA	23.90	2.40	
16	Allamore Hudspeth County	Dist. UA	23.90	2.40	
17	Camp 90 Hudspeth County	Dist. UA	23.90	2.40	
18	Country Club Anthony, NM	Dist. UA	13.80	2.40	
19	Eagler Flats Hudspeth County (Dees)	Dist. UA	23.90	2.40	
20	Faskin Hudspeth County	Dist. UA	23.90	2.40	
21	Gill-Neely Hudspeth County (Maverick)	Dist. UA	23.90	2.40	
22	Love Hudspeth County	Dist. UA	23.90	2.40	
23	Riverside Hudspeth County	Dist. UA	23.90	2.40	
24					
25					
26	PORTABLE SUBSTATIONS				
27	(All sizes)				
28	Mobile Substation	Dist. UA	13.80	0.48	
29	Mobile Substation	Dist. UA	115.00	13.80	
30	Mobile Substation	Dist. UA	115.00	13.80	
31	Mobile Substation	Dist. UA	69.00	2.40	
32	Mobile Substation No. 2	Dist. UA	24.90	2.40	
33	Mobile Substation No. 3	Dist. UA	13.80	2.40	
34					
35	SPARE TRANSFORMERS	N/A			
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) / /	Year/Period of Report End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

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

FOOTNOTE DATA

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.: 22 Column: a

Biggs substation is a switching distribution substation. The Company does not own the transformers on site.

Schedule | Page No.

Schedule	Page No.