



SOUTHERN CALIFORNIA
EDISON

An *EDISON INTERNATIONAL* Company



2010 FERC Form No. 1
ANNUAL REPORT OF
MAJOR ELECTRIC
UTILITIES, LICENSEES AND
OTHERS
<Click Here to Open>



2010 ANNUAL REPORT
TO THE
CALIFORNIA PUBLIC
UTILITIES COMMISSION
<Click Here to Open>

Thank you for accessing the 2010 FERC Form No. 1 and 2010 Annual Report to the CPUC electronically. Countless trees have been saved (not to mention time and money). We have tried to make it as user-friendly as possible. Click on the icon or report name to the left to open the report you would like to view.

FERC Form No. 1 NAVIGATION

The FERC Form 1 page numbering system does not correspond with the literal page numbers in this PDF File. You will find it easiest to navigate using the bookmarks on the left side of the screen.

CPUC Annual Report

Bookmarks have also been created in this file to simplify navigation of this report.

If you have any questions or comments, please contact Donna Perreira, Corporate Financial Reporting and Research at (626) 302-1214.

THIS FILING IS

Item 1: An Initial (Original) Submission OR Resubmission No. _____

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)



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)

Southern California Edison Company

Year/Period of Report

End of 2010/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.)

<u>Reference Schedules</u>	<u>Pages</u>
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 filed..."

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 Southern California Edison Company		02 Year/Period of Report End of <u>2010/Q4</u>
03 Previous Name and Date of Change <i>(if name changed during year)</i> / /		
04 Address of Principal Office at End of Period <i>(Street, City, State, Zip Code)</i> 2244 Walnut Grove Avenue, Rosemead, California 91770		
05 Name of Contact Person Chris C. Dominski		06 Title of Contact Person Vice President and Controller
07 Address of Contact Person <i>(Street, City, State, Zip Code)</i> 2244 Walnut Grove Avenue, Rosemead, California 91770		
08 Telephone of Contact Person, <i>Including Area Code</i> (626) 302-1398	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report <i>(Mo, Da, Yr)</i> 04/18/2011

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Chris C. Dominski	03 Signature Chris C. Dominski	04 Date Signed <i>(Mo, Da, Yr)</i> 04/15/2011
02 Title Vice President and Controller		

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

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	NONE
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	NONE
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NONE
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	NONE
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	
56	Amounts included in ISO/RTO Settlement Statements	397	
57	Purchase and Sale of Ancillary Services	398	
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

Name of Respondent
Southern California Edison Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/18/2011

Year/Period of Report
End of 2010/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	

Stockholders' Reports Check appropriate box:

- Two copies will be submitted
- No annual report to stockholders is prepared

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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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.

Ms. Chris C. Dominski, Vice President and Controller
Location: 2244 Walnut Grove Avenue, Rosemead, CA 91770
Mailing Address: P.O. Box 800, Rosemead, CA 91770

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.

California, July 6, 1909

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 in receivership.

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

Primarily engaged in electric utility service in the State of California and gas and water service on Santa Catalina Island in the State of California.

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) No

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report <i>(Mo, Da, Yr)</i> 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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CONTROL OVER RESPONDENT

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

Edison International holds control over respondent by way of 100% ownership of respondent's common stock which was acquired pursuant to a holding company reorganization effective July 1, 1988.

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	Bear Creek Uranium Company	Inactive.	-	
2	a Partnership			
3				
4				
5				
6	Edison ESI (Formerly Energy Service, Inc.)	Non-public utility engaged	100%	
7	a California Corporation	primarily in the business of		
8		furnishing energy services to		
9		commercial customers.		
10				
11				
12	Edison Material Supply LLC	Non-public utility engaged in	100%	
13	a Delaware Limited Liability Company	providing procurement, inven-		
14		tory and warehousing services		
15				
16	Mono Power Company	Inactive.	100%	
17	a California Company			
18				
19				
20				
21	SCE Capital Company	Inactive.	100%	
22	a Delaware Corporation			
23				
24	Southern States Realty (Formerly Southern	Non-public utility engaged	100%	
25	Surplus Realty Co.)	in holding real estate		
26	a California Corporation	interests.		
27				

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.

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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	SCE Trust I	Delaware business trust	-	
2		organized to act as a		
3		financing vehicle.		
4				
5	SCE Trust II	Delaware business trust	-	
6		organized to act as a		
7		financing vehicle.		
8				
9	SCE Trust III	Delaware business trust	-	
10		organized to act as a		
11		financing vehicle.		
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Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 103 Line No.: 1 Column: d

Bear Creek Uranium Company

Mono Power owns a 50% partnership interest in the Bear Creek Uranium Company; the remaining interest is owned by Anadarko Petroleum.

Schedule Page: 103 Line No.: 12 Column: d

Respondent is the only member of Edison Material Supply LLC.

Schedule Page: 103.1 Line No.: 1 Column: d

Respondent is the depositor.

Schedule Page: 103.1 Line No.: 5 Column: d

Respondent is the depositor.

Schedule Page: 103.1 Line No.: 9 Column: d

Respondent is the depositor.

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	Chairman of the Board &	Alan J. Fohrer	2,744,777
2	Chief Executive Officer*		
3			
4	President*	John R. Fielder	919,666
5			
6	Executive Vice President**	Pedro J. Pizarro	825,279
7			
8	Senior Vice President & Chief Financial Officer	Linda G. Sullivan	645,327
9			
10	Senior Vice President effective 11/15/2010 and Chief	Peter T. Dietrech	1,448,234
11	Nuclear Officer effective 12/09/2010		
12			
13			
14			
15	Pursuant to Item 402 of Regulation S-K, the		
16	informaton provided above was reported as "Salary,"		
17	"Bonus," "Non-Equity Incentive Plan Compensation"		
18	and "All Other Compensation" in the Summary		
19	Compensation Table of the Company's Proxy		
20	Statement filed with the Securities and Exchange		
21	Commission on March 18, 2011. For additional		
22	information required by Regulation S-K, Item 402,		
23	please see the Company's Proxy Statement.		
24			
25	* Retired on December 31, 2010		
26	** Became Edison Mission Group President effective		
27	01/01/2011		
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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	Theodore F. Craver, Jr. *** (1)	2244 Walnut Grove Avenue
2		P.O. Box 976, Rosemead, California 91770
3		
4		
5	Ronald L. Litzinger (2)	2244 Walnut Grove Avenue
6	President	P.O. Box 800, Rosemead, California 91770
7		
8		
9		
10	Alan J. Fohrer** (1) (3)	2244 Walnut Grove Avenue
11	Chairman of the Board and Chief Executive Officer	P.O. Box 800, Rosemead, California 91770
12		
13		
14		
15	Jagjeet S. Bindra	7113 Lake Edge Drive
16		Dallas, Texas 75230
17		
18		
19	Vanessa C.L. Chang	136 North Irving Boulevard
20		Los Angeles, California 90004
21		
22		
23	France A. Cordova	Hovde Hall, 610 Purdue Mall
24		West Lafayette, Indiana 47907-2040
25		
26		
27	Charles B. Curtis	1747 Pennsylvania Avenue, N.W., 7th Floor
28		Washington, DC 20006
29		
30		
31	Bradford M. Freeman *** (1)	11100 Santa Monica Blvd., Suite 1900
32		Los Angeles, California 90025
33		
34		
35	Luis G. Nogales	9229 West Sunset Boulevard, Suite 900
36		Los Angeles, California 90069
37		
38		
39	Ronald L. Olson*** (1)	355 South Grand Avenue, 35th Floor
40		Los Angeles, California 90071
41		
42		
43	James M. Rosser*** (1)	5151 State University Drive
44		Los Angeles, California 90032
45		
46		
47	Richard T. Schlosberg, III	800 E. Sonterra Boulevard, Suite 140
48		San Antonio, Texas 78258

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	Thomas C. Sutton*** (1)	111 Shorecliff Road
2		Corona del Mar, California 92625
3		
4		
5	Brett White	11150 Santa Monica Boulevard, Suite 1600
6		Los Angeles, California 90025
7		
8		
9		
10		
11	(1) The executive Committee ceased to exist as of	
12	April 22, 2010.	
13		
14	(2) Mr. Litzinger was elected President effective	
15	January 1, 2011.	
16		
17	(3) Mr. Fohrer served as Chairman of the Board,	
18	Chief Executive Officer and a Director until his	
19	Retirement on December 31, 2010.	
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?	<input checked="" type="checkbox"/> Yes <input type="checkbox"/> 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	FERC Electric Tariff, Volume 6	ER97-2355, ER03-338, ER06-788, ER10-135 (TRBAA)
2	FERC Electric Tariff, Volume 6	ER01-315, ER03-142, ER04-890, ER04-1209, ER05-763
3		ER10-105 (RSBAA)
4	FERC Electric Tariff, Volume 6	ER01-832, ER03-338, ER05-506, ER09-559,
5		ER10-675 (TACBAA)
6	FERC Electric Tariff, Volume 6	ER08-375, ER09-187, ER10-160 (CWIPBAA)
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Name of Respondent
Southern California Edison Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/18/2011

Year/Period of Report
End of 2010/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

Yes
 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	20091030-0055	10/29/2009	ER10-135	2010 TRBAA Update	FERC Electric Tariff,
2	20091028-0010	10/23/2009	ER10-105	2010 RSBAA Update	FERC Electric Tariff,
3	20100129-0211	01/29/2010	ER10-675	2010 TACBAA Update	FERC Electric Tariff,
4	20090126-0156	01/21/2009	ER09-559	2009 TACBAA Update	FERC Electric Tariff,
5	20081103-0189	10/31/2008	ER09-187	2009 CWIPBAA Update	FERC Electric Tariff,
6	20091102-0176	10/30/2009	ER10-160	2010 CWIPBAA Update	FERC Electric Tariff,
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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		NONE		
2				
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Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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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 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Question 1. Franchises

During 2010, there was one franchise change:

LA County Ord 7062
 Extension Agreement
 Extension granted through June 30, 2011 (18 month extension)
 Payments under 1937 Act beginning January, 2010

Question 2. Acquisition of ownership in other companies

None

Question 3. Purchase or sale of an operating unit or system

None

Question 4. Important leaseholds acquired or given

The following leasehold was executed during 2010:

Lessee Name: Logistics Terminals, Inc. A California Corporation
 Lease Start Date: September 1, 2010
 Initial Term: 25 Years (with option to extend four 10-year terms)
 Length: 65 years

Annual Rent:

Year 1: \$66,000; Year 2: \$264,000; Year 3: \$396,000; Year 4: \$396,000; Year 5: \$396,000; Year 6: \$403,900;
 Year 7: \$412,000; Year 8: \$420,250; Year 9: \$428,650; Year 10: \$437,200
 Year 11 - 25: *Subject to Reappraisal*
 Year 26 - 35: *Subject to Reappraisal (if applicable)*
 Year 36 - 45: *Subject to Reappraisal (if applicable)*
 Year 46 - 55: *Subject to Reappraisal (if applicable)*
 Year 56 - 65: *Subject to Reappraisal (if applicable)*

CPUC Application Date: 04/29/2009
 CPUC Decision Date: 10/16/2009
 CPUC Application Number: 09-10-011

Also see notes to financial statements on page 122-123

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Question 5: Important extension or reduction of transmission or distribution system

There were no major/significant extensions or reduction of SCE service territory during the year of 2010.

Question 6: Obligations

Long-Term Debt:

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2010A	03/11/2010	\$500	5.50%	03/15/2040	D. 07-08-012 dated Aug. 23, 2007
Series 2010 B	08/30/2010	\$500	4.50%	09/01/2040	D. 07-08-012 dated Aug. 23, 2007
California Statewide Communities Development Authority (CSCDA) Pollution Control Bonds 2010 Series A	09/21/2010	\$100	4.50%	09/01/2029	D. 03-12-004 dated Dec. 4, 2003 and D. 05-08-008 dated Aug. 25, 2005
Clark County, NV 2010 Series	12/16/2010	\$75	0.65%	06/01/2031	D. 05-08-008 dated Aug. 25, 2005

Short-Term Obligations:

There was no commercial paper outstanding on 12/31/2010.

Preferred Security Issuances:

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	DIVIDEND RATE	AUTHORIZING CPUC DECISION
None				

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Indemnities:

Indemnity Provided as Part of the Acquisition of Mountainview:

In connection with the acquisition of the Mountainview power plant, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of \$60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Mountainview Filter Cake Indemnity:

The Mountainview power plant utilizes water from on-site groundwater wells and City of Redlands ("City") recycled water for cooling purposes. Unrelated to the operation of the plant, the groundwater contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. SCE has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this indemnity.

Other Indemnities:

SCE provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. SCE has not recorded a liability related to these indemnities.

Question 7. Changes in articles of incorporation or amendments to charter

SCE has adopted a Certificate of Determination of Preferences of the Series D Preference Stock, effective March 7, 2011, in connection with the creation of a new series of preference stock.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Question 8. Wage Scale Changes

The following wage scale changes have occurred during 2010 (January 1, 2010 through December 31, 2010):

- Annual merit increase for non-represented employees implemented on 3/15/2010. Average increase was 3.0%.
- Salary structure for non-represented employees updated as of 1/22/2010. Average structure adjustment (changes to market reference points) was 1.6%.
- General Increases to UWUA and SOFA employees was 4% effective 1/1/2010
General Increases to IBEW employees was 4% effective 12/20/2010

Question 9. Materially important legal matters

Navajo Nation Litigation

There are updates to the Navajo Nation Litigation as reported in the FERC Form 3Q for the third quarter of 2010. A summary of the Navajo Nation Litigation matter is included in the Notes to Financials appearing on Pages 122-123 of this filing.

California Coastal Commission Potential Environmental Proceeding

In May 2010, the California Coastal Commission issued a NOV to SCE, its contractor, and certain property owners related to activity on a property that was used for equipment storage related to a nearby SCE electricity line undergrounding construction project. The NOV alleged that SCE, through its contractor, violated the California Coastal Act by removing without the appropriate permits approximately one acre of vegetation from the property, which was located in a protected coastal zone within and adjacent to the City of Newport Beach, California. In the NOV, the Coastal Commission indicated an interest in negotiating a settlement of the alleged violations but no settlement has been reached. The Coastal Act provides for penalties of up to \$30,000 per violation, which may be increased by up to \$15,000 per day per violation for knowing and intentional violations. SCE has sought indemnification from its contractor for liability associated with the NOV.

Question 10. Material transactions involving officers, directors, or security holders with a material interest in the transaction

Mr. Olson, an SCE Director, is a partner of the law firm of Munger, Tolles & Olson LLP ("MTO"), which provided legal services to SCE in 2010. Such services are expected to continue in the future. The amount paid by SCE to MTO for legal services during 2010 was \$6,463,841.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

SCE believes the terms and conditions of SCE's relationship with MTO are comparable to the terms and conditions of SCE's relationships with other law firms.

Except for those transactions disclosed in the Notes to Financials appearing on pages 122-123 of this filing, transactions between the respondent and its parent holding company and other affiliated entities are not understood to be subject to reporting in this item.

Question 11. Reserved

Question 12.

N/A

Question 13. Changes in: a) officers and directors, b) majority security holders, and c) voting powers of the respondent

a) Changes in officers and directors of the respondent

Changes in directors of the respondent since November 16, 2010, the date as of which this information was reported in the FERC Form 3Q for the third quarter 2010 are reflected below:

Director Name	Date Elected	Effective Date	End Date (if applicable)
Alan J. Fohrer	12/13/2001	01/01/2002	12/31/10
Ronald L. Litzinger	12/09/2010	01/01/2011	N/A

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

Changes in officers of the respondent since November 16, 2010 are reflected below.

Officer Name	Title	Date First Elected	Effective Date	End Date (if applicable)
Alan J. Fohrer	Chairman of the Board and Chief Executive Officer	04/26/2007	06/12/2007	12/31/2010
John R. Fielder	President	10/20/2005	10/20/2005	12/31/2010
Ronald L. Litzinger	President	12/09/2010	01/01/2011	N/A
Stephen E. Pickett	Executive Vice President	12/09/2010	01/01/2011	N/A
	Executive Vice President and General Counsel	12/09/2010	01/01/2011	02/24/2011
	Senior Vice President and General Counsel	12/13/2001	01/01/2002	12/31/2010
Pedro J. Pizarro	Executive Vice President	02/28/2008	04/01/2008	12/31/2010
Lynda L. Ziegler	Executive Vice President	12/09/2010	01/01/2011	N/A
	Senior Vice President	03/01/2006	03/01/2006	12/31/2010
Gaddi H. Vasquez	Senior Vice President	02/24/2011	02/24/2011	N/A
	Vice President	06/18/2009	07/27/2009	02/24/11
Russell C. Swartz	Senior Vice President and General Counsel	02/24/2011	02/24/2011	N/A
	Vice President and Associate General Counsel	02/25/2010	02/25/2010	02/24/11
Walter Rhodes	Vice President	02/24/2011	03/01/2011	N/A

b) Changes in majority security holders.

There have been no changes in the major security holders of SCE's voting stock.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

c) Changes in voting powers of the respondent.

SCE issued Series D Preference Stock on March 7, 2011. The voting rights for such stock are as follows:

The shares will have no voting rights except as set forth below or as otherwise provided by California law.

The holders of the shares are entitled to vote as a separate class with any other outstanding series of preference stock, or as series within the class, on certain matters affecting their interests. The affirmative vote or written consent of the holders of at least a majority of the shares of the affected class or series is required to:

- amend the articles of incorporation to adversely change certain basic terms of the shares with respect to dividends, redemption, liquidation, conversion, voting or priority; or
- authorize, create or increase in amount any class of stock ranking senior to the shares with respect to payment of dividends and distribution of our assets upon our liquidation, dissolution or winding up.

However, such vote or consent of the holders of preference stock will not be required if, at or prior to the time when any of the actions mentioned above takes place, all of the preference stock the consent of which would otherwise be required is redeemed in accordance with the articles of incorporation. On matters requiring their consent, holders of the shares will be entitled to one vote per share.

We may create and issue a new series of preference stock, or create a new class of shares that ranks equally with the shares with respect to payment of dividends and distribution of our assets upon our liquidation, dissolution or winding up, without the consent of the holders of the shares. We may in the future seek to increase the number of authorized shares of preference stock, which would require the affirmative vote or written consent of at least a majority of the outstanding shares of preference stock.

Question 14. Cash Management Programs

SCE does not currently participate in a cash management program.

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	33,499,779,697	31,007,955,042
3	Construction Work in Progress (107)	200-201	3,313,663,483	2,715,867,617
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		36,813,443,180	33,723,822,659
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	14,996,520,980	14,553,666,042
6	Net Utility Plant (Enter Total of line 4 less 5)		21,816,922,200	19,170,156,617
7	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab. (120.1)	202-203	222,201,551	194,707,148
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	372,420
9	Nuclear Fuel Assemblies in Reactor (120.3)		333,522,640	524,857,731
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	186,903,500	414,543,349
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		368,820,691	305,393,950
14	Net Utility Plant (Enter Total of lines 6 and 13)		22,185,742,891	19,475,550,567
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	OTHER PROPERTY AND INVESTMENTS			
18	Nonutility Property (121)		171,017,503	159,493,165
19	(Less) Accum. Prov. for Depr. and Amort. (122)		99,683,975	88,753,298
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	6,382,942	5,735,394
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	9,376,302	10,218,556
24	Other Investments (124)		696	696
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		3,552,966,288	3,212,752,529
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		367,074,029	187,063,444
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,007,133,785	3,486,510,486
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		6,616,296	24,744,057
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		399,400	143,498
38	Temporary Cash Investments (136)		249,585,830	349,107,605
39	Notes Receivable (141)		4,765	19,583
40	Customer Accounts Receivable (142)		618,808,785	571,353,600
41	Other Accounts Receivable (143)		258,178,547	230,893,332
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		85,458,718	52,872,045
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		17,652,059	50,259,445
45	Fuel Stock (151)	227	21,084,268	26,716,937
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	310,981,122	293,865,256
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	10,502,365	11,368,665

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		9,376,302	10,218,556
54	Stores Expense Undistributed (163)	227	0	0
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)		132,347,508	47,097,165
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		3,215,787	3,442,808
60	Rents Receivable (172)		6,933,364	3,197,893
61	Accrued Utility Revenues (173)		441,812,420	347,003,035
62	Miscellaneous Current and Accrued Assets (174)		172,537,311	35,765,884
63	Derivative Instrument Assets (175)		454,067,794	347,543,501
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		367,074,029	187,063,444
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)		2,242,818,572	2,092,368,219
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		59,702,555	49,888,391
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	3,338,071	3,610,164
72	Other Regulatory Assets (182.3)	232	4,468,687,781	4,021,347,846
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		286,245	2,657
77	Temporary Facilities (185)		577,119	701,177
78	Miscellaneous Deferred Debits (186)	233	221,641,646	215,767,918
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)		267,941,069	287,275,352
82	Accumulated Deferred Income Taxes (190)	234	824,817,442	982,748,991
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		5,846,991,928	5,561,342,496
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		34,282,687,176	30,615,771,768

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	2,168,054,319	2,168,054,319
3	Preferred Stock Issued (204)	250-251	920,004,950	920,004,950
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		923,708	923,708
7	Other Paid-In Capital (208-211)	253	585,772,712	565,090,441
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	14,566,180	14,558,320
11	Retained Earnings (215, 215.1, 216)	118-119	5,568,650,816	4,743,036,374
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	3,413,591	2,766,044
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-24,687,325	-18,727,801
16	Total Proprietary Capital (lines 2 through 15)		9,207,566,591	8,366,589,715
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	7,577,445,000	6,402,445,000
19	(Less) Reaquired Bonds (222)	256-257	323,585,000	467,985,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	400,783,845	825,828,700
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		27,742,650	20,214,142
24	Total Long-Term Debt (lines 18 through 23)		7,626,901,195	6,740,074,558
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		221,475,639	226,737,085
27	Accumulated Provision for Property Insurance (228.1)		122,642	122,642
28	Accumulated Provision for Injuries and Damages (228.2)		227,870,250	231,716,755
29	Accumulated Provision for Pensions and Benefits (228.3)		1,851,580,251	1,526,885,310
30	Accumulated Miscellaneous Operating Provisions (228.4)		18,640,000	179,368,979
31	Accumulated Provision for Rate Refunds (229)		57,536,529	0
32	Long-Term Portion of Derivative Instrument Liabilities		449,354,067	495,541,900
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,507,141,608	3,180,825,808
35	Total Other Noncurrent Liabilities (lines 26 through 34)		5,333,720,986	5,841,198,479
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		1,227,957,190	1,156,179,782
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		6,930,672	17,716,339
41	Customer Deposits (235)		216,958,423	238,012,655
42	Taxes Accrued (236)	262-263	44,236,166	8,875,809
43	Interest Accrued (237)		172,377,086	165,206,244
44	Dividends Declared (238)		5,516,060	105,415,394
45	Matured Long-Term Debt (239)		0	0

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)		22,939,096	22,569,795
48	Miscellaneous Current and Accrued Liabilities (242)		630,081,740	602,993,928
49	Obligations Under Capital Leases-Current (243)		5,261,446	8,351,630
50	Derivative Instrument Liabilities (244)		660,998,518	597,526,461
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		449,354,067	495,541,900
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)		2,543,902,330	2,427,306,137
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		111,926,989	136,843,391
57	Accumulated Deferred Investment Tax Credits (255)	266-267	118,381,707	96,642,359
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	771,107,213	736,520,923
60	Other Regulatory Liabilities (254)	278	2,685,464,766	1,262,049,690
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)		2,716,355,512	2,196,379,359
64	Accum. Deferred Income Taxes-Other (283)		3,167,359,887	2,812,167,157
65	Total Deferred Credits (lines 56 through 64)		9,570,596,074	7,240,602,879
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		34,282,687,176	30,615,771,768

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 column in 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	10,397,607,168	9,948,634,865		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	6,005,135,469	5,607,793,838		
5	Maintenance Expenses (402)	320-323	533,942,036	489,254,649		
6	Depreciation Expense (403)	336-337	1,056,340,753	992,263,902		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	202,934,648	130,650,940		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	277,692	371,381		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		238,081	136,046		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		502,133,839	689,545,836		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	260,414,299	242,036,658		
15	Income Taxes - Federal (409.1)	262-263	-149,430,164	211,349,420		
16	- Other (409.1)	262-263	-3,992,342	179,839,199		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	644,334,788	233,905,355		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	-40,270,374	71,100,683		
19	Investment Tax Credit Adj. - Net (411.4)	266	20,891,172	-4,778,073		
20	(Less) Gains from Disp. of Utility Plant (411.6)		382,284	55,701		
21	Losses from Disp. of Utility Plant (411.7)		57,666			
22	(Less) Gains from Disposition of Allowances (411.8)		867,033	1,414,808		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		9,112,298,994	8,699,797,959		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,285,308,174	1,248,836,906		

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 purchases, 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		Line No.
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)	
						1
10,392,073,023	9,942,797,532	2,714,498	1,993,463	2,819,647	3,843,870	2
						3
6,001,172,891	5,601,683,885	2,058,815	1,846,704	1,903,763	4,263,249	4
532,398,983	488,709,900	393,587	132,369	1,149,466	412,380	5
1,055,460,810	991,296,380	126,520	160,215	753,423	807,307	6
						7
202,934,648	130,650,940					8
277,692	371,381					9
238,081	136,046					10
						11
502,133,839	689,545,836					12
						13
260,159,367	241,824,822	41,942	43,576	212,990	168,260	14
-148,782,432	212,235,852	-23,703	-40,414	-624,029	-846,018	15
-3,852,497	180,040,623	-6,268	-11,131	-133,577	-190,293	16
644,308,623	234,005,003	26,165	-99,648			17
-40,270,374	71,100,683					18
20,891,172	-4,778,073					19
382,284	55,701					20
57,666						21
867,033	1,414,808					22
						23
						24
9,106,419,900	8,693,151,403	2,617,058	2,031,671	3,262,036	4,614,885	25
1,285,653,123	1,249,646,129	97,440	-38,208	-442,389	-771,015	26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		1,285,308,174	1,248,836,906		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		52,362,751	53,141,395		
34	(Less) Expenses of Nonutility Operations (417.1)		39,952,715	39,719,537		
35	Nonoperating Rental Income (418)		338,936	310,738		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	647,547	25,145,963		
37	Interest and Dividend Income (419)		100,686,141	275,171,162		
38	Allowance for Other Funds Used During Construction (419.1)		102,638,687	115,853,243		
39	Miscellaneous Nonoperating Income (421)		8,286,127	-68,869,647		
40	Gain on Disposition of Property (421.1)		298,539	1,211,677		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		225,306,013	362,244,994		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		1,600,316	869,476		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		17,286,085	14,741,836		
46	Life Insurance (426.2)		-25,432,291	-22,995,584		
47	Penalties (426.3)		8,084,980	-12,089,131		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		12,432,551	9,833,898		
49	Other Deductions (426.5)		11,612,825	-22,072,559		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		25,584,466	-31,712,064		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,553,540	1,622,714		
53	Income Taxes-Federal (409.2)	262-263	-31,690,955	-40,333,652		
54	Income Taxes-Other (409.2)	262-263	-8,662,405	-11,006,879		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	298,486			
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-37,501,334	-49,717,817		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		237,222,881	443,674,875		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		381,695,303	361,335,364		
63	Amort. of Debt Disc. and Expense (428)		29,746,743	32,573,654		
64	Amortization of Loss on Reaquired Debt (428.1)					
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)			476,191		
68	Other Interest Expense (431)		62,146,360	52,993,844		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		42,677,222	31,787,441		
70	Net Interest Charges (Total of lines 62 thru 69)		430,911,184	415,591,612		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,091,619,871	1,276,920,169		
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)		1,091,619,871	1,276,920,169		

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		4,601,570,215	3,676,681,760
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Credit: Dividends Received from Subsidiaries - Net			22,939,138
5	Credit: Transfer of Mountainview's Equity			13,434,554
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			36,373,692
10	Debit: Reacquired Capital Stock Expense			
11	Debit: Stock Option Exercises		-11,212,884	(3,379,726)
12	Debit: Shares Purchased for Performance Shares			
13	Debit: Deividend Equivalentns on Deferred Compensation		-2,245,987	(3,989,932)
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-13,458,871	(7,369,658)
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,090,972,324	1,251,774,206
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriations of Retained Earnings		-4,885,782	(5,003,152)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,885,782	(5,003,152)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred Stock Dividends			
25				
26	Preferred Stock Dividends (see footnote)		-51,899,012	(50,886,633)
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-51,899,012	(50,886,633)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends		-200,000,000	(300,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-200,000,000	(300,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		5,422,298,874	4,601,570,215
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		146,351,942	141,466,159
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		146,351,942	141,466,159
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		5,568,650,816	4,743,036,374
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		2,766,044	559,219
50	Equity in Earnings for Year (Credit) (Account 418.1)		647,547	25,145,963
51	(Less) Dividends Received (Debit)			22,939,138
52				
53	Balance-End of Year (Total lines 49 thru 52)		3,413,591	2,766,044

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Southern California Edison Company		04/18/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 118 Line No.: 26 Column: c

NOTES TO STATEMENT OF RETAINED EARNINGS FOR THE
YEAR TO DATE DECEMBER 31, 2010

	Dividend Per Share	
Cumulative Preferred -		
4.08% Series	\$1.02	663,000
4.24% Series	1.06	1,272,001
4.32% Series	1.08	1,785,703
4.78% Series	1.195	1,549,642
\$100 Preference Stock -		
* Series A	Various	22,378,666
6.125% Series B	6.125	12,250,000
6.000% Series C	6.000	12,000,000
 Total Preferred Dividends		 <u>51,899,012</u>

* Variable rate

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)	1,091,619,871	1,276,920,169
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,258,911,231	1,122,454,747
5	Amort of Nuc. Fuel, Loss on Reacq. Debt, Perm. & Disc. of L/T Debt	105,853,257	109,373,984
6	Regulatory Assets and Liabilities - Long Term	167,797,905	1,719,486,921
7	Dividends received from unconsolidated subsidiary		22,939,138
8	Deferred Income Taxes (Net)	738,232,255	696,548,306
9	Investment Tax Credit Adjustment (Net)	21,739,348	-4,283,864
10	Net (Increase) Decrease in Receivables	-26,657,681	40,293,985
11	Net (Increase) Decrease in Inventory	-11,483,198	7,956,353
12	Net (Increase) Decrease in Allowances Inventory	24,045	-11,368,665
13	Net Increase (Decrease) in Payables and Accrued Expenses	-47,553,692	16,289,855
14	Net (Increase) Decrease in Other Regulatory Assets	-257,504,101	484,252,772
15	Net Increase (Decrease) in Other Regulatory Liabilities	370,624,532	-743,499,830
16	(Less) Allowance for Other Funds Used During Construction	102,638,687	115,853,243
17	(Less) Undistributed Earnings from Subsidiary Companies	647,547	25,145,963
18	Other (provide details in footnote):		
19	Accrued Taxes	35,360,357	-99,201,458
20	Prepayments and Other Current Assets	-318,976,989	243,868,309
21	Other - Net	360,455,187	-799,849,390
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	3,385,156,093	3,941,182,126
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-3,464,962,295	-2,730,298,824
27	Gross Additions to Nuclear Fuel	-137,103,045	-121,100,856
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-12,946,703	-3,460,946
30	(Less) Allowance for Other Funds Used During Construction	-102,638,687	-115,853,243
31	Other (provide details in footnote):		
32	Cost of Removal, Salvage Value and Others	-268,853,623	-250,124,258
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-3,781,226,979	-2,989,131,641
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	1,545,301	2,831,407
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		9,568,623
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)		

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other: Proceeds from Sale of Nuclear Decommissioning Trust investments	1,431,577,247	2,216,531,802
54	Purchases of Nuclear Decommissioning Trust investments and other	-1,650,467,691	-2,415,463,428
55	Customer Advances for construction and other investments	-6,760,471	-37,813,435
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-4,005,332,593	-3,213,476,672
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	1,118,790,700	738,895,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68	Tax benefit related to stock-based awards	3,558,644	6,670,516
69	Proceeds from Stock Option Exercises	17,933,241	5,579,978
70	Cash Provided by Outside Sources (Total 61 thru 69)	1,140,282,585	751,145,494
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-258,396,485	-374,065,775
74	Preferred Stock	-7,860	
75	Common Stock		
76	Other (provide details in footnote):		
77	Shares Purchased for Stock-based Compensation	-27,297,028	-8,600,513
78	Net Decrease in Short-Term Debt (c)		-1,892,625,000
79	Dividends on Preference Stock	-46,528,000	-45,646,000
80	Dividends on Preferred Stock	-5,270,346	-5,270,347
81	Dividends on Common Stock	-300,000,000	-300,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	502,782,866	-1,875,062,141
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-117,393,634	-1,147,356,687
87			
88	Cash and Cash Equivalents at Beginning of Period	373,995,160	1,521,351,847
89			
90	Cash and Cash Equivalents at End of period	256,601,526	373,995,160

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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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 Commission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Recquired Debt, and 257, Unamortized Gain on Recquired 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.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

GLOSSARY

When the following terms and abbreviations appear in the text of this report, they have the meanings indicated below.

2010 Tax Relief Act	Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010
AFUDC	allowance for funds used during construction
APS	Arizona Public Service Company
ARO(s)	asset retirement obligation(s)
Bcf	Billion cubic feet
CAA	Clean Air Act
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CAMR	Clean Air Mercury Rule
CARB	California Air Resources Board
CDWR	California Department of Water Resources
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DOE	U. S. Department of Energy
ERRA	energy resource recovery account
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FGIC	Financial Guarantee Insurance Company
FIP(s)	federal implementation plan(s)
Four Corners	coal fueled electric generating facility located in Farmington, New Mexico in which SCE holds a 48% ownership interest
GAAP	generally accepted accounting principles
GHG	greenhouse gas
Global Settlement	A settlement between Edison International and the IRS that resolves all of SCE's federal income tax disputes and affirmative claims for tax years 1986 through 2002 and related matters with state tax authorities.
GRC	General Rate Case
IRS	Internal Revenue Service
ISO	Independent System Operator
kWh(s)	kilowatt-hour(s)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations in this report
Mohave	two coal fueled electric generating facilities that no longer operate located in Clark County, Nevada in which SCE holds a 56% ownership interest
Moody's	Moody's Investors Service
MRTU	Market Redesign Technical Upgrade
MW	megawatts
MWh	megawatt-hours
NAAQS	national ambient air quality standards
NERC	North American Electric Reliability Corporation
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NO _x	nitrogen oxide
NRC	Nuclear Regulatory Commission
NSR	New Source Review
Palo Verde	large pressurized water nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PBOP(s)	postretirement benefits other than pension(s)
PBR	Performance-based ratemaking

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NOTES TO FINANCIAL STATEMENTS (Continued)			

PG&E	Pacific Gas & Electric Company
PSD	Prevention of Significant Deterioration
QF(s)	qualifying facility(ies)
ROE	return on equity
S&P	Standard & Poor's Ratings Services
San Onofre	large pressurized water nuclear electric generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SIP(s)	state implementation plan(s)
SO ₂	sulfur dioxide
SRP	Salt River Project Agricultural Improvement and Power District
US EPA	U.S. Environmental Protection Agency
VIE(s)	variable interest entity(ies)

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Item 1. Notes to Consolidated Financial Statements

General Note

SCE is an investor-owned public utility primarily engaged in the business of supplying electricity to an approximately 50,000 square-mile area of southern California. SCE is a wholly-owned subsidiary of Edison International.

These financial statements are prepared in accordance with the requirements of 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. These notes include specific information requested by the FERC. See the Company's Annual Report to Shareholders as of, and for the year-ended, December 31, 2010 for financial statements and complete footnotes prepared in accordance with accounting principles generally accepted in the United States.

SCE follows accounting principles for rate-regulated enterprises which are required for entities whose rates are set by regulators at levels intended to recover the estimated costs of providing service, plus a return on net investment, or rate base. Regulators may also impose certain penalties or grant certain incentives. Due to timing and other differences in the collection of revenue, these principles allow a cost that would otherwise be charged as an expense by an unregulated entity to be capitalized as a regulatory asset if it is probable that such cost is recoverable through future rates; conversely the principles allow creation of a regulatory liability for amounts collected in rates to recover costs expected to be incurred in the future or amounts collected in excess of costs incurred. SCE's management assess at the end of each reporting period whether regulatory assets are probable of future recovery by considering factors such as the current regulatory environment, the issuance of rate orders on recovery of the specific or a similar incurred cost to SCE or other rate-regulated entities in California, and other factors that would indicate that the regulator will treat an incurred cost as allowable for rate-making purposes.

Financial statements prepared in conformity with FERC as set forth in its applicable Uniform System of Accounts and published accounting releases require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingency assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Actual results could differ from those estimates.

SCE's outstanding common stock is owned entirely by its parent company, Edison International.

The following are material differences between FERC reporting standards and GAAP:

- Variable Interest Entities

SCE has variable interests in certain QFs that contain variable contract pricing provisions based on the price of natural gas. Further, four of these contracts are with entities that are partnerships owned in part by a related party, EME. These four contracts had 20-year terms at inception. The QFs sell electricity to SCE and steam to nonrelated parties. In accordance with previously issued authoritative accounting guidance for variable interest entities, in 2009 SCE consolidated these four projects under GAAP. These four projects were not consolidated under FERC reporting standards, and are not accounted for as an equity investment since SCE has no ownership interest. Based on new authoritative guidance, effective January 1, 2010, SCE deconsolidated these four projects under GAAP, which is consistent with FERC reporting standards.

- Equity Investment Differences

SCE accounts for its investments in majority-owned subsidiaries using the equity method rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries which is required by GAAP. In general, the accounting for investments in majority-owned subsidiaries using the equity method rather than the consolidate method in accordance with GAAP has no effect on net income or retained earnings. Due to the nature of the business, SCE continues to consolidate Edison Material and Supplies.

- Asset Impairments

For FERC reporting purposes, asset impairments related to SCE's nuclear and coal investments are written-off against the accumulated

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NOTES TO FINANCIAL STATEMENTS (Continued)			

provision for depreciation of electric utility plant. FERC requires electric plant in service to be reported at its original cost and does not permit a company to reduce the amount recorded in electric plant in service below its original cost. As a result, asset impairments and additions made prior to cost-of-service ratemaking are recorded in the accumulated provision for depreciation of electric utility plant, as the Uniform System of Accounts allows extraordinary property losses to be credited to this account. Under cost-of-service ratemaking, additions to SCE's nuclear and coal plant investments are recorded in electric plant in service.

Under GAAP, asset impairments related to SCE's nuclear and coal investments are written-off against the original amounts recorded in both electric plant in service and accumulated provision for depreciation of electric utility plant. In accordance with accounting principles for rate-regulated enterprises, SCE concluded that its asset impairments related to nuclear and coal investments, including additions made prior to cost-of-service ratemaking, were probable of recovery, and recorded a regulatory asset. Under cost-of-service ratemaking, SCE's additions to nuclear and coal plant are recorded in electric plant in service.

- Asset Retirement Obligation

The accumulated net removal costs for SCE's regulated plant assets that do not meet the definition of an ARO or a conditional ARO under authoritative accounting guidance are classified as regulatory liabilities under GAAP and as accumulated depreciation under FERC.

- Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity

Preferred stock subject to mandatory redemption is classified as a liability under GAAP and as proprietary capital under FERC. Also, dividends on preferred stock subject to mandatory redemption subsequent to July 1, 2003, are classified as interest expense under GAAP and as a reduction of retained earnings under FERC.

- Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans

For FERC reporting purposes, the asset for an overfunded postretirement defined benefit plan is classified on the FERC financial statements as special funds, a noncurrent asset. For GAAP reporting purposes, this asset is classified as a miscellaneous deferred debit, which is also a noncurrent asset.

- Other Differences

The FERC required current maturities of long-term debt to be included as part of long-term debt, while GAAP requires such maturities to be classified as a current liability. Accumulated deferred income taxes are classified as current and noncurrent for GAAP, while FERC classifies all accumulated deferred income taxes as noncurrent. Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets and liabilities as noncurrent. Retained earnings are presented differently under the Uniform System of Accounts for FERC purposes than it is for GAAP purposes. Additionally, the FERC requires only current year presentation of statements of cash flows and retained earnings while GAAP requires a comparative presentation.

Certain prior-year amounts were reclassified to conform to the December 31, 2010 financial statement presentation.

Commitments

Third-Party Power Purchase Agreements

SCE enters into various agreements to purchase power and electric capacity, including:

- *Renewable Energy Contracts* – California law requires retail sellers of electricity to comply with an RPS by purchasing renewable energy (such as biomass, small hydroelectric, wind, solar, and geothermal energy), so that the amount of electricity delivered from eligible renewable resources equals at least 20% of their total retail sales by the end of 2010 or such later date as is permitted by flexible compliance rules. Renewable contract payments generally consist of payments based on a fixed price per megawatt hour. As of December 31, 2010, SCE had 97 renewable energy contracts that were approved by the CPUC and met critical contract

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NOTES TO FINANCIAL STATEMENTS (Continued)			

provisions which expire at various dates between 2011 and 2033.

- *Qualifying Facility Power Purchase Agreements* – Under the Public Utility Regulatory Policies Act of 1978 (“PURPA”), electric utilities are required to purchase energy and capacity from independent power producers that are qualifying co-generation facilities and qualifying small power production facilities (“QFs”). As of December 31, 2010, SCE had 170 QF contracts which expire at various dates between 2011 and 2026.
- *Other Power Purchase Agreements* – In accordance with the SCE’s CPUC-approved long-term procurement plans, SCE has entered into capacity agreements with third parties, including 14 tolling arrangements, 47 power call options and 106 resource adequacy contracts. SCE’s obligations under a portion of these agreements are limited to payments for the availability of such resources.

At December 31, 2010, the undiscounted future expected payments for power purchase agreements that have been approved by the CPUC and have completed major milestones for construction were as follows:

(in millions)	Renewable Energy Contracts	QF Power Purchase Agreements	Other Purchase Agreements
2011	\$340	\$429	\$548
2012	494	411	616
2013	568	411	748
2014	633	410	638
2015	634	399	468
Thereafter	11,007	1,663	3,336
Total future commitments	\$13,676	\$3,723	\$6,354

Some of the power purchase agreements that SCE entered into with independent power producers are treated as operating and capital leases. The following table shows the future fixed capacity payments due under the contracts that are treated as operating and capital leases (these amounts are also included in the table above). The fixed capacity payments for capital leases are discounted to their present value in the table below using SCE’s incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	Operating Leases	Capital Leases
2011	\$740	\$33
2012	717	71
2013	761	131
2014	708	153
2015	693	154
Thereafter	8,741	2,479
Total future commitments	\$12,360	\$3,021
Amount representing executory costs		(628)
Amount representing interest		(1,168)
Net commitments		\$1,225

Operating lease expense for these power purchase agreements was \$350 million in 2010, \$358 million in 2009 and \$328 million in 2008. The timing of SCE’s recognition of the lease expense conforms to ratemaking treatment for SCE’s recovery of the cost of electricity. The amounts above do not include payments related to CDWR purchases for the benefit of SCE’s customers, as SCE is acting as an agent for the CDWR.

Capital leases are reported as long-term obligations on the consolidated balance sheets. As a rate regulated enterprise, SCE’s capital lease amortization expense and interest expense are reflected in “Purchased power” on the consolidated statements of income.

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NOTES TO FINANCIAL STATEMENTS (Continued)			

At December 31, 2010 and 2009, net capital leases reflected in "Utility plant" on the consolidated balance sheets were \$227 million and \$235 million, including amortization of \$22 million and \$13 million, respectively. SCE had \$5 million and \$8 million included in "Other current liabilities" and \$222 million and \$227 million included in "Other deferred credits and other liabilities," representing the present value of the fixed capacity payments due under these contracts recorded on the consolidated balance sheets at December 31, 2010 and 2009, respectively.

Both capital and operating leases have varying terms, provisions and expiration dates. The contingent rentals for capital leases were less than \$1 million for both 2010 and 2009.

Other Lease Commitments

The following summarizes the estimated minimum future commitments for noncancelable other operating leases (excluding power purchase agreements discussed above):

<u>(in millions)</u>	Operating Leases – Other
2011	\$61
2012	60
2013	56
2014	51
2015	45
Thereafter	<u>255</u>
Total future commitments	<u>\$528</u>

Minimum lease payments under operating leases for property, plant and equipment are levelized (total minimum lease payments divided by the number of years of the lease) and recorded as rent expense over the terms of the leases. Lease payments in excess of the minimum are recorded as rent expense in the year incurred.

Operating lease expense for other leases (primarily related to vehicles, office space and other equipment) were \$62 million in 2010, \$47 million in 2009 and \$47 million in 2008. Operating leases have varying terms, provisions and expiration dates.

Nuclear Decommissioning

In 2003, SCE recorded the fair value of its liability for AROs related to the decommissioning of its nuclear power facilities. At that time, SCE adjusted its nuclear decommissioning obligation, capitalized the initial costs of the ARO into a nuclear-related ARO regulatory asset and also recorded an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of costs through the ratemaking process. Decommissioning cost estimates are updated in each NDCTP. Once a Commission decision is rendered, a revised ARO layer reflecting the updated cost estimate is established and accreted over the lives of San Onofre and Palo Verde.

SCE plans to decommission its nuclear generating facilities by a prompt removal method authorized by the NRC. Decommissioning is expected to begin after expiration of the plants' operating licenses. The plants' initial operating licenses are currently set to expire in 2022 for San Onofre Units 2 and 3, unless license renewal proves feasible, and 2024, 2025 and 2027 for Palo Verde units 1, 2 and 3, respectively. Decommissioning costs, which are recovered through nonbypassable customer rates over the term of each nuclear facility's operating license, are recorded as a component of depreciation expense, with a corresponding credit to the ARO regulatory liability. Amortization of the ARO asset (included within the unamortized nuclear investment) and accretion of the ARO liability are

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deferred as increases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The cost of removal amounts, in excess of fair value collected for assets not legally required to be removed, are classified as regulatory liabilities.

Due to regulatory recovery of SCE's nuclear decommissioning expense, nuclear decommissioning activities do not affect SCE's earnings.

SCE's nuclear decommissioning trust investments primarily consist of debt and equity investments that are classified as available-for-sale. Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on electric utility revenue. Unrealized gains and losses on decommissioning trust funds increase or decrease the trust assets and the related regulatory asset or liability and have no impact on electric utility revenue or decommissioning expense. SCE reviews each security for other-than-temporary impairment on the last day of each month. If the fair value on the last day of two consecutive months is less than the cost for that security, SCE recognizes a loss for the other-than-temporary impairment. If the fair value is greater or less than the cost for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

SCE has collected in rates amounts for the future costs of removal of its nuclear assets, and has placed those amounts in independent trusts. The recorded liability to decommission SCE's nuclear power facilities is \$2.4 billion as of December 31, 2010, based on site-specific studies performed in 2008 for San Onofre and 2007 for Palo Verde. Changes in the estimated costs, timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission. SCE estimates that it will spend approximately \$8.6 billion through 2053 to decommission its active nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 1.8% to 6.9% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately \$23 million per year. Contributions received in prior years were approximately \$46 million. SCE estimates annual after-tax earnings on the decommissioning funds of 4.2% to 5.7%. If the assumed return on trust assets is not earned, it is probable that additional funds needed for decommissioning will be recoverable through rates in the future. If the assumed return on trust assets is greater than estimated, funding amounts may be reduced through future decommissioning proceedings.

All of SCE's San Onofre Unit 1 decommissioning costs will be paid from its nuclear decommissioning trust funds and are subject to CPUC review. The estimated remaining cost to decommission San Onofre Unit 1 is recorded as an ARO liability of \$63 million at December 31, 2010. Total expenditures for the decommissioning of San Onofre Unit 1 were \$596 million from the beginning of the project in 1998 through December 31, 2010.

Decommissioning expense under the ratemaking method was \$30 million in 2010 and \$46 million in both 2009 and 2008. The ARO for decommissioning SCE's active nuclear facilities was \$2.4 billion and \$3.1 billion at December 31, 2010 and 2009, respectively.

See "Nuclear Decommissioning Trusts" in "Fair Value Measurements" below for discussion on fair value of the trust.

Other Commitments

Certain other commitments for the years 2011 through 2015 are estimated below:

(in millions)	2011	2012	2013	2014	2015
Fuel supply contracts	\$260	\$178	\$189	\$143	\$166
Other contractual obligations	5	7	7	7	7

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase. SCE has a coal fuel contract that requires payment of certain fixed charges whether or not coal is delivered.

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Indemnities

Indemnity Provided as Part of the Acquisition of Mountainview

In connection with the acquisition of the Mountainview power plant, SCE agreed to indemnify the seller with respect to specific environmental claims related to SCE's previously owned San Bernardino Generating Station, divested by SCE in 1998 and reacquired as part of the Mountainview acquisition. SCE retained certain responsibilities with respect to environmental claims as part of the original divestiture of the station. The aggregate liability for either party to the purchase agreement for damages and other amounts is a maximum of \$60 million. This indemnification for environmental liabilities expires on or before March 12, 2033. SCE has not recorded a liability related to this indemnity.

Mountainview Filter Cake Indemnity

The Mountainview power plant utilizes water from on-site groundwater wells and City of Redlands ("City") recycled water for cooling purposes. Unrelated to the operation of the plant, the groundwater contains perchlorate. The pumping of the water removes perchlorate from the aquifer beneath the plant and concentrates it in the plant's wastewater treatment "filter cake." Use of this impacted groundwater for cooling purposes was mandated by Mountainview's California Energy Commission permit. SCE has indemnified the City for cleanup or associated actions related to groundwater contaminated by perchlorate due to the disposal of filter cake at the City's solid waste landfill. The obligations under this agreement are not limited to a specific time period or subject to a maximum liability. SCE has not recorded a liability related to this indemnity.

Other Indemnities

SCE provides other indemnifications through contracts entered into in the normal course of business. These are primarily indemnifications against adverse litigation outcomes in connection with underwriting agreements, and specified environmental indemnities and income taxes with respect to assets sold. SCE's obligations under these agreements may be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties for certain indemnities. The obligated amounts of these indemnifications often are not explicitly stated, and the overall maximum amount of the obligation under these indemnifications cannot be reasonably estimated. SCE has not recorded a liability related to these indemnities.

Compensation and Benefit Plans

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of \$76 million in 2010, \$70 million in 2009 and \$65 million in 2008.

Pension Plans and Postretirement Benefits Other Than Pensions

Pension Plans

Noncontributory defined benefit pension plans (some with cash balance features) cover most employees meeting minimum service requirements. SCE recognizes pension expense for its nonexecutive plan as calculated by the actuarial method used for ratemaking. The expected contributions (all by the employer) are approximately \$102 million for the year ending December 31, 2011. Annual contributions made to most of SCE's pension plans are recovered through CPUC-approved regulatory mechanisms. Annual contributions to these plans are expected to be, at a minimum, equal to the related annual expense.

Volatile market conditions have affected the value of SCE's trusts established to fund its future long-term pension benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trusts declined 35% during 2008. This reduction in the value of plan assets resulted in a change in the pension plan funding status from overfunded to underfunded and will also result in increased future expense and increased future contributions. Improved market conditions in 2009 and 2010 partially offset the impacts of the 2008 market conditions.

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Changes in the plan's funded status also affect the assets and liabilities recorded on the consolidated balance sheets. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to these trusts. The Pension Protection Act of 2006 established new minimum funding standards and placed various restrictions on underfunded plans.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31,	
	2010	2009
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	\$3,389	\$3,175
Service cost	132	107
Interest cost	193	191
Amendments	5	21
Actuarial loss	185	57
Benefits paid	(172)	(162)
Projected benefit obligation at end of year	\$3,732	\$3,389
Change in plan assets		
Fair value of plan assets at beginning of year	\$2,726	\$2,238
Actual return on plan assets	414	551
Employer contributions	98	99
Benefits paid	(172)	(162)
Fair value of plan assets at end of year	\$3,066	\$2,726
Funded status at end of year	\$(666)	\$(663)
Amounts recognized in the consolidated balance sheets:		
Current liabilities	\$(6)	\$(5)
Long-term liabilities	(660)	(658)
	\$(666)	\$(663)
Amounts recognized in accumulated other comprehensive loss consist of:		
Net loss	\$42	\$31
Amounts recognized as a regulatory asset:		
Prior service cost	\$40	\$42
Net loss	500	556
	\$540	\$598
Total not yet recognized as expense	\$582	\$629
Accumulated benefit obligation at end of year	\$3,436	\$3,086
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	\$3,732	\$3,389
Accumulated benefit obligation	3,436	3,086
Fair value of plan assets	3,066	2,726
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.25%	6.0%
Rate of compensation increase	5.0%	5.0%

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Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31,		
	2010	2009	2008
Service cost	\$132	\$107	\$104
Interest cost	193	191	184
Expected return on plan assets	(201)	(162)	(249)
Amortization of prior service cost	8	11	17
Amortization of net loss	17	54	3
Expense under accounting standards	\$149	\$201	\$59
Regulatory adjustment—deferred	(52)	(94)	(5)
Total expense recognized	\$97	\$107	\$54

Other changes in plan assets and benefit obligations recognized in other comprehensive income:

(in millions)	Years ended December 31,		
	2010	2009	2008
Net loss (gain)	\$15	\$11	\$(2)
Amortization of net loss	(4)	(4)	(3)
Total recognized in other comprehensive (income) loss	\$11	\$7	\$(5)
Total recognized in expense and other comprehensive income	\$107	\$114	\$49

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of its postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost that will be amortized to expense in 2011 are \$17 million and \$7 million, respectively; \$6 million of the net loss is expected to be reclassified from accumulated other comprehensive income.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31,		
	2010	2009	2008
Discount rate	6.0%	6.25%	6.25%
Rate of compensation increase	5.0%	5.0%	5.0%
Expected return on plan assets	7.5%	7.5%	7.5%

The following are benefit payments, which reflect expected future service, expected to be paid:

(in millions)	Years ended December 31,
2011	\$262
2012	271
2013	278
2014	285
2015	296
2016 – 2020	1,542

Postretirement Benefits Other Than Pensions

Most non-union employees retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, vision and life insurance and other benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's hire date. The expected contributions (all by the employer) to the PBOP trust are \$54 million for the year ending December 31, 2011. Annual contributions made to SCE plans are recovered through

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CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

Volatile market conditions have affected the value of Edison International's trusts established to fund its future other postretirement benefits. The market value of the investments (reflecting investment returns, contributions and benefit payments) within the plan trust declined 33% during 2008. This reduction in the value of plan assets resulted in an increase in the plan's underfunded status and will also result in increased future expense and increased future contributions. Improved market conditions in 2009 and 2010 partially offset the impacts of the 2008 market conditions.

Changes in the plan's funded status affect the assets and liabilities recorded on SCE's consolidated balance sheets. Due to SCE's regulatory recovery treatment, the recognition of the funded status is offset by regulatory liabilities and assets. In the 2009 GRC, SCE requested recovery of and continued balancing account treatment for amounts contributed to this trust.

Information on plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31,	
	2010	2009
Change in benefit obligation		
Benefit obligation at beginning of year	\$2,011	\$2,247
Service cost	34	28
Interest cost	121	116
Amendments	12	(63)
Actuarial loss (gain)	203	(233)
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(108)	(104)
Benefit obligation at end of year	\$2,295	\$2,011
Change in plan assets		
Fair value of plan assets at beginning of year	\$1,459	\$1,212
Actual return on assets	175	256
Employer contributions	58	75
Plan participants' contributions	17	15
Medicare Part D subsidy received	5	5
Benefits paid	(108)	(104)
Fair value of plan assets at end of year	\$1,606	\$1,459
Fund status at end of year	\$(689)	\$(552)
Amounts recognized in the consolidated balance sheets consist of:		
Current liabilities	\$(17)	\$(16)
Long-term liabilities	(672)	(536)
	\$(689)	\$(552)
Amounts recognized as a regulatory asset (liability):		
Prior service credit	\$(161)	\$(209)
Net loss	718	625
Total not yet recognized as expense	\$557	\$416
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	5.5%	6.0%
Assumed health care cost trend rates:		
Rate assumed for following year	9.75%	8.25%
Ultimate rate	5.5%	5.5%
Year ultimate rate reached	2019	2016

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Expense components and other amounts recognized in other comprehensive income:

Expense components are:

(in millions)	Years ended December 31,		
	2010	2009	2008
Service cost	\$34	\$28	\$38
Interest cost	121	116	130
Expected return on plan assets	(100)	(81)	(122)
Amortization of prior service credit	(37)	(32)	(29)
Amortization of net loss	35	44	14
Total expense	\$53	\$75	\$31

In accordance with authoritative guidance on rate-regulated enterprises, SCE records regulatory assets and liabilities instead of charges and credits to other comprehensive income (loss) for the portion of its postretirement benefit plans that are recoverable in utility rates. The estimated net loss and prior service cost (credit) that will be amortized to expense in 2011 are \$36 million and \$(36) million, respectively.

The following are weighted-average assumptions used to determine expense:

	Years ended December 31,		
	2010	2009	2008
Discount rate	6.0%	6.25%	6.25%
Expected return on plan assets	7.0%	7.0%	7.0%
Assumed health care cost trend rates:			
Current year	8.25%	8.75%	8.75%
Ultimate rate	5.5%	5.5%	5.0%
Year ultimate rate reached	2016	2016	2015

Increasing the health care cost trend rate by one percentage point would increase the accumulated benefit obligation as of December 31, 2010 by \$263 million and annual aggregate service and interest costs by \$15 million. Decreasing the health care cost trend rate by one percentage point would decrease the accumulated benefit obligation as of December 31, 2010 by \$219 million and annual aggregate service and interest costs by \$13 million.

The following benefit payments are expected to be paid:

(in millions)	Years ended December 31,	
	Before Subsidy ¹	Net
2011	\$93	\$88
2012	108	102
2013	118	111
2014	126	119
2015	133	125
2016 – 2020	796	742

¹ Medicare Part D prescription drug benefits

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Plan Assets

Description of Pension and Postretirement Benefits Other Than Pensions Investment Strategies

The investment of plan assets is overseen by a fiduciary investment committee. Plan assets are invested using a combination of asset classes, and may have active and passive investment strategies within asset classes. Target allocations for pension plan assets are 30% for U.S. equities, 16% for non-U.S. equities, 35% for fixed income, 15% for opportunistic and/or alternative investments and 4% for other investments. Target allocations for PBOP plan assets are 41% for U.S. equities, 17% for non-U.S. equities, 34% for fixed income, 7% for opportunistic and/or alternative investments, and 1% for other investments. Edison International employs multiple investment management firms. Investment managers within each asset class cover a range of investment styles and approaches. Risk is managed through diversification among multiple asset classes, managers, styles and securities. Plan, asset class and individual manager performance is measured against targets. Edison International also monitors the stability of its investment managers' organizations.

Allowable investment types include:

United States Equities: Common and preferred stocks of large, medium, and small companies which are predominantly United States-based.

Non-United States Equities: Equity securities issued by companies domiciled outside the United States and in depository receipts which represent ownership of securities of non-United States companies.

Fixed Income: Fixed income securities issued or guaranteed by the United States government, non-United States governments, government agencies and instrumentalities including municipal bonds, mortgage backed securities and corporate debt obligations. A small portion of the fixed income positions may be held in debt securities that are below investment grade.

Opportunistic, Alternative and Other Investments:

Opportunistic: Investments in short to intermediate term market opportunities. Investments may have fixed income and/or equity characteristics and may be either liquid or illiquid.

Alternative: Limited partnerships that invest in non-publicly traded entities.

Other: Investments diversified among multiple asset classes such as global equity, fixed income currency and commodities markets. Investments are made in liquid instruments within and across markets. The investment returns are expected to approximate the plans' expected investment returns.

Asset class portfolio weights are permitted to range within plus or minus 3%. Where approved by the fiduciary investment committee, futures contracts are used for portfolio rebalancing and to reallocate portfolio cash positions. Where authorized, a few of the plans' investment managers employ limited use of derivatives, including futures contracts, options, options on futures and interest rate swaps in place of direct investment in securities to gain efficient exposure to markets. Derivatives are not used to leverage the plans or any portfolios.

Determination of the Expected Long-Term Rate of Return on Assets

The overall expected long-term rate of return on assets assumption is based on the long-term target asset allocation for plan assets and capital markets return forecasts for asset classes employed. A portion of the PBOP trust asset returns are subject to taxation, so the expected long-term rate of return for these assets is determined on an after-tax basis.

Capital Markets Return Forecasts

Capital markets return forecasts are based on long-term strategic planning assumptions from an independent firm which uses its research, modeling and judgment to forecast rates of return for global asset classes. In addition, a separate analysis of expected returns

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is conducted. The estimated total return for fixed income securities is based on historic long-term United States government bonds data. The estimated total return for intermediate United States government bonds is based on historic and projected data. The estimated rate of return for U.S. equities, non-U.S. equities and hedge funds includes a 3% premium over the estimated total return for intermediate United States government bonds. The rate of return for private equity is estimated to be a 3% premium over public equity, reflecting a premium for higher volatility and illiquidity.

Fair Value of Plan Assets

The PBOP Plan and the Southern California Edison Company Retirement Plan Trust (Master Trust) assets include investments in equity securities, U.S. treasury securities, other fixed-income securities, common/collective funds, mutual funds, other investment entities, foreign exchange and interest rate contracts, and partnership/joint ventures. Equity securities, U.S. treasury securities, mutual and money market funds are classified as Level 1 as fair value is determined by observable, unadjusted quoted market prices in active or highly liquid and transparent markets. Common/collective funds are valued at the net asset value (NAV) of shares held. Although common/collective funds are determined by observable prices, they are classified as Level 2 because they trade in markets that are less active and transparent. The fair value of the underlying investments in equity mutual funds and equity common/collective funds are based upon stock-exchange prices. The fair value of the underlying investments in fixed-income common/collective funds, fixed-income mutual funds and other fixed income securities including municipal bonds are based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information. Foreign exchange and interest rate contracts are classified as Level 2 because the values are based on observable prices but are not traded on an exchange. Futures contracts trade on an exchange and therefore are classified as Level 1. One of the partnerships is classified as Level 2 since this investment can be readily redeemed at NAV and the underlying investments are liquid publicly traded fixed-income securities which have observable prices. The remaining partnerships/joint ventures are classified as Level 3 because fair value is determined primarily based upon management estimates of future cash flows. Other investment entities are valued similarly to common collective funds and are therefore classified as Level 2. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable at NAV and classified as Level 2 and are discussed further at footnote 6 to the pension plan master trust investments table below.

Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2010 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks ¹	\$786	\$—	\$—	\$786
Common/collective funds ²	—	600	—	600
Corporate bonds ³	—	555	—	555
Partnerships/joint ventures ⁴	—	155	345	500
U.S. government and agency securities ⁵	84	316	—	400
Registered investment companies ⁶	84	169	—	253
Other investment entities ⁷	—	159	—	159
Interest-bearing cash	5	—	—	5
Other	2	30	—	32
Total	\$961	\$1,984	\$345	\$3,290
Receivables and payables, net				(55)
Net plan assets available for benefits				\$3,235
SCE's share of net plan assets				\$3,066

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The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Corporate stocks ¹	\$678	\$—	\$—	\$678
Common/collective funds ²	—	612	—	612
Corporate bonds ³	—	469	—	469
Partnerships/joint ventures ⁴	—	101	240	341
U.S. government and agency securities ⁵	104	352	—	456
Registered investment companies ⁶	73	58	—	131
Other investment entities ⁷	—	135	—	135
Interest-bearing cash	5	—	—	5
Foreign exchange contracts	—	6	—	6
Other	—	7	—	7
Total	\$860	\$1,740	\$240	\$2,840
Receivables and payables, net				17
Net plan assets available for benefits SCE's share of net plan assets				\$2,857
				\$2,726

¹ Corporate stocks are diversified. For 2010 and 2009, respectively, performance is primarily benchmarked against the Russell Indexes (63% and 61%) and Morgan Stanley Capital International (MSCI) index (37% and 39%).

² At December 31, 2010 and 2009, respectively, the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's (S&P 500) Index (29% and 33%), Russell 200 and Russell 1000 indexes (28% and 26%) and the MSCI Europe, Australasia and Far East (EAFE) Index (11% and 10%). A non-index U.S. equity fund representing 23% and 20% of this category as of December 31, 2010 and 2009, respectively, is actively managed. Another fund representing 8% and 7% of this category as of December 31, 2010 and 2009, respectively, is a global asset allocation fund.

³ Corporate bonds are diversified. At December 31, 2010 and 2009, respectively, this category includes \$65 million and \$52 million for collateralized mortgage obligations and other asset backed securities of which \$17 million and \$12 million are below investment grade.

⁴ Partnerships/joint venture Level 2 investments consist primarily of a partnership which invests in publicly traded fixed income securities, primarily from the banking and finance industry and U.S. government agencies. Approximately 60% of the Level 3 partnerships are invested in asset backed securities including distressed mortgages. The remaining Level 3 partnerships are invested in small private equity and venture capital funds. Investment strategies for these funds include branded consumer products, early stage technology, California geographic focus, and diversified US and non-US fund-of-funds.

⁵ Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal National Mortgage Association and the Federal Home Loan Mortgage Corporation.

⁶ Level 1 of registered investment companies consists of a global equity mutual fund which seeks to outperform the MSCI World Total Return Index. Level 2 of this category primarily consists of (1) short-term, emerging market and high yield bond funds and (2) a hedge fund that invests through liquid instruments in a global diversified portfolio of equity, fixed income, interest rate, foreign currency and commodities markets.

⁷ At December 31, 2010 and 2009, respectively, 57% and 64% of the other investment entities balance is invested in emerging market equity securities. At December 31, 2010 and 2009, respectively, about 24% and 17% of the assets in this category are invested in domestic mortgage backed securities. Most of the remaining funds invest in below grade fixed income securities

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including foreign issuers.

At December 31, 2010 and 2009, approximately 69% and 67%, respectively, of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of Level 3 investments for 2010 and 2009:

(in millions)	2010	2009
Fair value, net at beginning of period	\$240	\$111
Actual return on plan assets:		
Relating to assets still held at end of period	42	34
Relating to assets sold during the period	24	6
Purchases and dispositions, net	39	89
Transfers in and /or out of Level 3	—	—
Fair value, net at end of period	\$345	\$240

Postretirement Benefits Other than Pensions

The following table sets forth the PBOP Plan's financial assets that were accounted for at fair value as of December 31, 2010 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds ¹	\$—	\$657	\$—	\$657
Corporate stocks ²	344	—	—	344
Corporate notes and bonds ³	—	184	—	184
Registered investment companies ⁴	144	1	—	145
Partnerships ⁵	—	16	92	108
U.S. government and agency securities ⁶	50	38	—	88
Interest bearing cash	12	—	—	12
Other ⁷	4	76	—	80
Total	\$554	\$972	\$92	\$1,618
Receivables and payables, net				(12)
Combined net plan assets available for benefits				\$1,606

The following table sets forth the PBOP Plan's financial assets that were accounted for at fair value as of December 31, 2009 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	Total
Common/collective funds ¹	\$—	\$648	\$—	\$648
Corporate stocks ²	250	—	—	250
Corporate notes and bonds ³	—	151	—	151
Registered investment companies ⁴	213	—	—	213
Partnerships ⁵	—	—	49	49
U.S. government and agency securities ⁶	39	28	—	67
Interest bearing cash	14	—	—	14
Other ⁷	3	74	—	77
Total	\$519	\$901	\$49	\$1,469
Receivables and payables, net				(10)
Combined net plan assets available for benefits				\$1,459

¹ 61% of the common/collective assets are invested in a large cap index fund which seeks to track performance of the Russell 1000 index. 23% of the assets in this category are in index funds which seek to track performance in the MSCI Europe,

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Australasia and Far East (EAFE) Index. 7% of this category is invested in a privately managed bond fund and 6% in a fund which invests in equity securities the fund manager believes are undervalued.

- 2 Corporate stock performance is primarily benchmarked against the Russell Indexes (65% and 67%) and the MSCI All Country World (ACWI) index (35% and 33%) for 2010 and 2009, respectively.
- 3 Corporate notes and bonds are diversified and include approximately \$15 million and \$10 million for commercial collateralized mortgage obligations and other asset backed securities at December 31, 2010 and 2009, respectively.
- 4 Level 1 registered investment companies consist of an investment grade corporate bond mutual fund and a money market fund.
- 5 At December 31, 2010 and 2009, respectively, 84% and 90% of the Level 3 partnerships category is invested in (1) asset backed securities including distressed mortgages and (2) distressed companies.
- 6 Level 1 U.S. government and agency securities are U.S. treasury bonds and notes. Level 2 primarily relates to the Federal Home Loan Mortgage Corporation and the Federal National Mortgage Association.
- 7 Other includes \$64 million and \$58 million of municipal securities at December 31, 2010 and 2009, respectively.

At December 31, 2010 and 2009, approximately 67% and 76%, respectively, of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

The following table sets forth a summary of changes in the fair value of PBOP Level 3 investments for 2010 and 2009:

<u>(in millions)</u>	<u>2010</u>	<u>2009</u>
Fair value, net at beginning of period	\$49	\$12
Actual return on plan assets		
Relating to assets still held at end of period	14	12
Relating to assets sold during the period	—	1
Purchases and dispositions, net	29	27
Transfers in and /or out of Level 3	—	(3)
Fair value, net at end of period	<u>\$92</u>	<u>\$49</u>

Stock-Based Compensation

Stock options, performance shares, deferred stock units and restricted stock units have been granted under Edison International's long-term incentive compensation programs. Edison International usually does not issue new common stock for equity awards settled. Rather, a third party is used to facilitate the exercise of stock options and the purchase and delivery of outstanding common stock for settlement of option exercises, performance shares and restricted stock units. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in Edison International's common stock. Deferred stock units granted to management are settled in cash, and represent a liability. Restricted stock units are settled in common stock; however, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

SCE recognizes stock-based compensation expense on a straight-line basis over the requisite service period. SCE recognizes stock-based compensation expense for awards granted to retirement-eligible participants as follows: for stock-based awards granted prior to January 1, 2006, SCE recognized stock-based compensation expense over the explicit requisite service period and accelerated any remaining unrecognized compensation expense when a participant actually retired; for awards granted or modified after January 1, 2006, to participants who are retirement-eligible or will become retirement-eligible prior to the end of the normal requisite service period for the award, stock-based compensation is recognized on a prorated basis over the initial year or over the period between the

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date of grant and the date the participant first becomes eligible for retirement.

Edison International maintains a shareholder approved incentive plan (the 2007 Performance Incentive Plan) that includes stock-based compensation. The maximum number of shares of Edison International's common stock authorized to be issued or transferred pursuant to awards under the 2007 Performance Incentive Plan, as amended in 2009, is 21.5 million shares, plus the number of any shares subject to awards issued under Edison International's prior plans and outstanding as of April 26, 2007, which expire, cancel or terminate without being exercised or shares being issued ("carry-over shares"). As of December 31, 2010, Edison International had approximately 9 million shares remaining for future issuance under its stock-based compensation plans.

Stock Options

Under various plans, SCE has granted stock options at exercise prices equal to the average of the high and low price and, beginning in 2007, at the closing price at the grant date. Edison International may grant stock options and other awards related to or with a value derived from its common stock to directors and certain employees. Options generally expire 10 years after the grant date and vest over a period of four years of continuous service, with expense recognized evenly over the requisite service period, except for awards granted to retirement-eligible participants.

Stock options granted in 2003 through 2006 accrue dividend equivalents for the first five years of the option term. Stock options granted in 2007 and later have no dividend equivalent rights except for options granted to Edison International's Board of Directors in 2007. Unless transferred to nonqualified deferral plan accounts, dividend equivalents accumulate without interest. Dividend equivalents are paid in cash after the vesting date. Edison International has discretion to pay certain dividend equivalents in shares of Edison International common stock. Additionally, Edison International will substitute cash awards to the extent necessary to pay tax withholding or any government levies.

The fair value for each option granted was determined as of the grant date using the Black-Scholes option-pricing model. The Black-Scholes option-pricing model requires various assumptions noted in the following table.

	Years ended December 31,		
	2010	2009	2008
Expected terms (in years)	7.3	7.4	7.4
Risk-free interest rate	2.0% – 3.2%	2.8% – 3.5%	2.6% – 3.8%
Expected dividend yield	3.3% – 4.0%	3.6% – 5.0%	2.3% – 3.9%
Weighted-average expected dividend yield	3.8%	4.9%	2.5%
Expected volatility	18.8% – 19.8%	20% – 21%	17% – 19%
Weighted-average volatility	19.8%	20.6%	17.3%

The expected term represents the period of time for which the options are expected to be outstanding and is primarily based on historical exercise and post-vesting cancellation experience and stock price history. The risk-free interest rate for periods within the contractual life of the option is based on a zero coupon U.S. Treasury issued STRIPS (separate trading of registered interest and principal of securities) whose maturity equals the option's expected term on the measurement date. Expected volatility is based on the historical volatility of Edison International's common stock for the lesser of 1) the period from January 1, 2003 through the last month-end prior to the grant date or 2) the length of the option's expected term. The volatility period used was 87 months, 84 months and 72 months at December 31, 2010, 2009 and 2008, respectively.

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The following is a summary of the status of Edison International stock options granted to SCE employees:

	Weighted Average			
	Stock Options	Exercise Price	Remaining Contractual Term (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2009	8,749,015	\$31.91		
Granted	2,199,716	\$33.38		
Expired	(\$10,587)	\$49.03		
Forfeited	(\$145,516)	\$31.32		
Exercised	(\$756,446)	\$22.94		
Affiliate transfers – net	28,554	\$36.33		
Outstanding at December 31, 2010	10,064,736	\$32.86	6.32	
Vested and expected to vest at December 31, 2010	9,815,717	\$32.88	6.26	80,399,824
Exercisable at December 31, 2010	5,283,358	\$33.30	4.55	44,826,129

At December 31, 2010, there was \$11 million of total unrecognized compensation cost related to stock options, net of expected forfeitures. That cost is expected to be recognized over a weighted-average period of approximately two years.

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2008, March 2009 and March 2010, and vest at the end of December 2010, 2011 and 2012, respectively. Performance shares awarded contain dividend equivalent reinvestment rights. An additional number of target contingent performance shares will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's performance shares is dependent upon a market condition and three years of continuous service subject to a prorated adjustment for employees who are terminated under certain circumstances or retire, but payment cannot be accelerated. The market condition is based on Edison International's total shareholder return relative to the total shareholder return of a specified group of peer companies at the end of a three-calendar-year period. The number of performance shares earned is determined based on Edison International's ranking among these companies. Performance shares earned are settled half in cash and half in common stock; however, Edison International has discretion under certain of the awards to pay the half subject to cash settlement in common stock. Edison International also has discretion to pay certain dividend equivalents in Edison International common stock. Additionally, cash awards are substituted to the extent necessary to pay tax withholding or any government levies. The portion of performance shares that can be settled in cash is classified as a share-based liability award. The fair value of these shares is remeasured at each reporting period and the related compensation expense is adjusted. The portion of performance shares payable in common stock is classified as a share-based equity award. Compensation expense related to these shares is based on the grant-date fair value. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined, except for awards granted to retirement-eligible participants.

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The fair value of performance shares is determined using a Monte Carlo simulation valuation model. The Monte Carlo simulation valuation model requires various assumptions noted in the following table.

	Years ended December 31,		
	2010	2009	2008
Equity awards			
Grant date risk-free interest rate	1.3%	1.3%	3.9%
Grant date expected volatility	21.6%	21.4%	17.4%
Liability awards ¹			
Expected volatility	20.6%	21.9%	19.2%
Risk-free interest rate:			
2010 awards	0.6%	—	—
2009 awards	0.3%	1.1%	—
2008 awards	—	0.5%	0.8%

¹ The portion of performance shares classified as share-based liability awards are revalued at each reporting period.

The risk-free interest rate is based on the daily spot rate on the grant or valuation date on U.S. Treasury zero coupon issue or STRIPS with terms nearest to the remaining term of the performance shares and is used as a proxy for the expected return for the specified group of peer companies. Expected volatility is based on the historical volatility of Edison International's (and the specified group of peer companies') common stock for the most recent 36 months. Historical volatility for each company in the specified group is obtained from a financial data services provider.

At December 31, 2010, there was \$2 million (based on the December 31, 2010 fair value of performance shares classified as equity awards) of total unrecognized compensation cost related to performance shares. That cost is expected to be recognized over a weighted-average period of approximately two years.

The following is a summary of the status of Edison International nonvested performance shares:

	Equity Awards		Liability Awards	
	Shares	Weighted Average Grant Date Fair Value	Shares	Weighted Average Fair Value
Nonvested at December 31, 2009	172,604	\$36.65	172,604	
Granted	83,306	\$32.19	83,306	
Forfeited	(36,797)	\$54.51	(36,797)	
Affiliate transfers – net	791	\$41.62	791	
Nonvested at December 31, 2010	219,904	\$32.15	219,904	\$37.68

The current portion of nonvested performance shares classified as liability awards is reflected in "Other current liabilities" and the long-term portion is reflected in "Pensions and benefits" on the consolidated balance sheets.

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Restricted Stock Units

Restricted stock units were awarded to executives in March 2008, March 2009 and March 2010 and vest and become payable in January 2011, 2012 and 2013, respectively. Each restricted stock unit awarded is a contractual right to receive one share of Edison International common stock, if vesting requirements are satisfied. Restricted stock units awarded contain dividend equivalent reinvestment rights. An additional number of restricted stock units will be credited based on dividends on Edison International common stock for which the ex-dividend date falls within the performance period. The vesting of Edison International's restricted stock units is dependent upon continuous service through the end of the three-calendar-year-plus-two-days vesting period. Vesting is subject to a pro-rated adjustment for employees who are terminated under certain circumstances or retire. Cash awards are substituted to the extent necessary to pay tax withholding or any government levies.

The following is a summary of the status of Edison International nonvested restricted stock units granted to SCE employees:

	Restricted Stock Units	Weighted Average Grant Date Fair Value
Nonvested at December 31, 2009	238,835.00	32.87
Granted	160,684.00	33.38
Forfeited	(9,292.00)	33.47
Paid Out	(5,619.00)	37.68
Affiliate transfers – net	1,269.00	46.82
Nonvested at December 31, 2010	385,877.00	32.90

The fair value for each restricted stock unit awarded is determined as the closing price of Edison International common stock on the grant date.

Compensation expense related to these shares, which is based on the grant-date fair value, is recognized ratably over the requisite service period, except for awards whose holders become eligible for retirement vesting during the service period, in which case recognition is accelerated into the year the holders become eligible for retirement vesting. At December 31, 2010, there was \$4 million of total unrecognized compensation cost related to restricted stock units, net of expected forfeitures, which is expected to be recognized as follows: \$3 million in 2011 and \$1 million in 2012.

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Supplemental Data on Stock Based Compensation

(in millions, except per award amounts)	Years ended December 31,		
	2010	2009	2008
Stock Based Compensation Expense ¹			
Stock options	\$10	\$8	\$12
Performance shares	6	3	—
Restricted stock units	5	3	2
Other	6	6	1
Total stock based compensation expense	\$27	\$20	\$15
Income tax benefits related to stock compensation expense	\$11	\$8	\$6
Excess tax benefits ²	4	7	4
Stock options			
Weighted average grant date fair value per option granted	\$4.87	\$3.06	\$10.19
Fair value of options vested	11	8	12
Cash used to purchase shares to settle options	27	9	30
Cash from participants to exercise stock options	18	6	17
Value of options exercised	9	3	13
Tax benefits from options exercised	4	1	5
Performance Shares Classified as Equity Awards			
Weighted average grant date fair value per share granted	\$32.19	\$21.56	\$55.55
Fair value of shares vested	3	1	2
Value of shares settled	—	—	5
Tax benefits realized from settlement of awards	—	—	2
Performance Shares Classified as Liability Awards			
Value of shares settled	\$—	\$—	\$6
Tax benefits realized from settlement of awards	—	—	2
Restricted Stock units ³			
Weighted average grant date fair value per unit granted	\$33.38	\$25.32	\$49.83

¹ Reflected in “Operations and maintenance” on the consolidated statements of income.

² Reflected in “Settlements of stock based compensation – net” in the financing section of the consolidated statements of cash flows.

³ The value of restricted stock units settled was less than \$1 million for 2010, 2009 and 2008.

Derivative Instruments and Hedging Activities

SCE records derivative instruments on its consolidated balance sheets as either assets or liabilities measured at fair value unless otherwise exempted from derivative treatment as normal purchases or sales. The normal purchases and sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Changes in the fair value of derivative instruments are expected to be recovered from or refunded to customers through regulatory mechanisms and, therefore, SCE’s fair value changes have no impact on purchased-power expense or earnings. SCE does not use hedge accounting for derivative transactions due to regulatory accounting treatment.

Where SCE’s derivative instruments are subject to a master netting agreement and certain criteria are met, SCE presents its derivative assets and liabilities on a net basis on its consolidated balance sheets. In addition, derivative positions are offset against margin and cash collateral deposits. The results of derivative activities are recorded as part of cash flows from operating activities on the consolidated statements of cash flows. See Note 6 for further information on derivative and hedging activities.

SCE uses derivative financial instruments to manage exposure to commodity price risk. SCE manages these risks in part by entering into forward commodity transactions, including options, swaps and futures. SCE is exposed to credit loss in the event of nonperformance by counterparties. To mitigate credit risk from counterparties, master netting agreements are used whenever possible

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and counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Commodity Price Risk

SCE is exposed to commodity price risk which represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's hedging program reduces ratepayer exposure to variability in market prices related to SCE's power and gas activities. As part of this program, SCE enters into energy options, swaps, forward arrangements, tolling arrangements and CRRs. These transactions are pre-approved by the CPUC or executed in compliance with CPUC-approved procurement plans. SCE recovers its related hedging costs through the ERRA balancing account, and as a result, exposure to commodity price risk is not expected to impact earnings, but may impact cash flows.

SCE's electricity price exposure arises from energy produced and sold in CAISO's MRTU market as a result of differences between SCE's load requirements versus the amount of energy delivered from its generating facilities, existing bilateral contracts and CDWR contracts allocated to SCE.

A portion of SCE's purchased power supply is subject to natural gas price volatility. SCE's natural gas price exposure arises from purchasing natural gas for generation at the Mountainview power plant and peaker plants, from bilateral contracts where pricing is based on natural gas prices (this includes contract energy prices for most renewable QFs which are based on the monthly index price of natural gas delivered at the southern California border), and power contracts in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Notional Volumes of Derivative Instruments

The following table summarizes the notional volumes of derivatives used for hedging activities:

Commodity	Unit of Measure	Economic Hedges	
		December 31, 2010	2009
Electricity options, swaps and forward arrangements	GWh	32,138	14,868
Natural gas options, swaps and forward arrangements	Bcf	250	266
Congestion revenue rights	GWh	181,291	195,367
Tolling arrangements ¹	GWh	114,599	116,398

¹ In compliance with a CPUC mandate, SCE held an open, competitive solicitation that produced power purchase agreements with different project developers who have agreed to construct new southern California generating resources. SCE has entered into a number of contracts which are recorded as derivative instruments. The contracts provide for fixed capacity payments as well as pricing for energy delivered based on a heat rate and variable operation and maintenance prices. However, due to uncertainty regarding the availability of required emission credits, some of the generating resources may not be constructed and the contracts associated with these resources could therefore terminate, at which time SCE would no longer account for these contracts as derivatives.

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Fair Value of Derivative Instruments

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2010:

(in millions)	Derivative Assets			Derivative Liabilities			Net Liability
	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Non-trading activities							
Economic hedges	\$87	\$367	\$454	\$216	\$449	\$665	\$211
Netting and collateral	—	—	—	(\$4)	—	(\$4)	(\$4)
Total	\$87	\$367	\$454	\$212	\$449	\$661	\$207

The following table summarizes the gross and net fair values of commodity derivative instruments at December 31, 2009:

(in millions)	Derivative Assets			Derivative Liabilities			Net Liability
	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Non-trading activities							
Economic hedges	\$160	\$187	\$347	\$102	\$496	\$598	\$251

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased-power expense and expects to recover these costs from ratepayers. As a result, realized gains and losses are not reflected in earnings, but may temporarily affect cash flows. Due to expected future recovery from ratepayers, unrealized gains and losses are recorded as regulatory assets and liabilities and therefore are also not reflected in earnings. The results of derivative activities and related regulatory offsets are recorded in cash flows from operating activities in the consolidated statements of cash flows.

The following table summarizes the components of economic hedging activity:

(in millions)	Years ended December 31,		
	2010	2009	2008
Realized gains/(losses)	\$(156)	\$(344)	\$(60)
Unrealized gains/(losses)	36	470	(638)

Contingent Features/Credit Related Exposure

Certain derivative instruments and power procurement contracts under SCE's power and natural gas hedging activities contain collateral requirements. SCE has historically provided collateral in the form of cash and/or letters of credit for the benefit of counterparties. These requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments and other factors.

Certain of these power contracts contain a provision that requires SCE to maintain an investment grade credit rating from each of the major credit rating agencies, referred to as a "credit-risk-related contingent feature." If SCE's credit rating were to fall below investment grade, SCE may be required to pay the derivative liability or post additional collateral. The aggregate fair value of all derivative liabilities with these credit-risk-related contingent features was \$67 million and \$91 million as of December 31, 2010 and 2009, respectively, for which SCE has posted \$4 million collateral to its counterparties. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2010, SCE would be required to post an additional \$2 million of collateral.

As part of SCE's procurement activities, SCE contracts with a number of utilities, energy companies, financial institutions, and other companies, collectively referred to as counterparties. If a counterparty were to default on its contractual obligations, SCE could be exposed to potentially volatile spot markets for buying replacement power or selling excess power. In addition, SCE would be exposed to the risk of non-payment of accounts receivable, primarily related to sales of excess energy and realized gains on derivative

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instruments. However, all of the contracts that SCE has entered into with counterparties are either entered into under SCE's short-term or long-term procurement plan which has been approved by the CPUC, or the contracts are approved by the CPUC before becoming effective. As a result of regulatory recovery mechanisms, losses from non-performance are not expected to affect earnings, but may temporarily affect cash flows.

To manage credit risk, SCE looks at the risk of a potential default by counterparties. Credit risk is measured by the loss that would be incurred if counterparties failed to perform pursuant to the terms of their contractual obligations. To mitigate credit risk from counterparties, master netting agreements are used whenever possible and counterparties may be required to pledge collateral when deemed necessary.

Margin and Collateral Deposits

Margin and collateral deposits include cash deposited with counterparties and brokers, and cash received from counterparties and brokers as credit support under energy contracts. The amount of margin and collateral deposits generally varies based on changes in the fair value of the related positions. SCE nets counterparty receivables and payables where balances exist under master netting arrangements. SCE presents the portion of its margin and collateral deposits netted with its derivative positions on its consolidated balance sheets. The following table summarizes margin and collateral deposits provided to and received from counterparties:

(in millions)	December 31,	
	2010	2009
Collateral provided to counterparties:		
Offset against derivative liabilities	\$4	\$—
Reflected in other current assets	5	6
Collateral received from counterparties:		
Reflected in other current liabilities	\$60	\$59

Income Taxes

SCE and its subsidiaries are included in Edison International's consolidated federal income tax and combined state franchise tax returns. Pursuant to an income tax-allocation agreement approved by the CPUC, SCE's tax liability is computed as if it filed its federal and state income tax returns on a separate return basis. SCE estimates its income taxes for each jurisdiction in which it operates. This involves estimating current period tax expense along with assessing temporary differences resulting from differing treatment of items (such as depreciation) for tax and accounting purposes. These differences result in deferred tax assets and liabilities, which are included within SCE's consolidated balance sheets. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Interest income, interest expense and penalties associated with income taxes are reflected in "Income tax expense" on the consolidated statements of income. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties.

Management evaluates its uncertain tax positions at each reporting date. Liabilities for uncertain tax positions are reflected in "Accrued taxes" and "Other deferred credits and long-term liabilities" on the consolidated balance sheets.

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Current and Deferred Taxes

The components of income tax expense by location of taxing jurisdiction are:

(in millions)	Years ended December 31,		
	2010	2009	2008
Current:			
Federal	\$(145)	\$(82)	\$53
State	(71)	173	43
	(216)	91	96
Deferred:			
Federal	663	200	232
State	(7)	(42)	14
	656	158	246
Total	\$440	\$249	\$342

The components of net accumulated deferred income tax liability are:

(in millions)	December 31,	
	2010	2009
Deferred tax assets:		
Property and software related	\$655	\$630
Regulatory balancing accounts	230	229
Unrealized gains and losses	389	315
Pensions and PBOPs	176	213
Other	490	525
Total	\$1,940	\$1,912
Deferred tax liabilities:		
Property-related	\$5,520	\$4,371
Capitalized software costs	293	286
Regulatory balancing accounts	293	257
Unrealized gains and losses	389	315
Other	264	256
Total	\$6,759	\$5,485
Accumulated deferred income tax liability – net	\$4,819	\$3,573
Classification of accumulated deferred income taxes – net:		
Included in deferred credits and other liabilities	\$4,829	\$3,651
Included in current assets	\$10	\$78

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Effective Tax Rate

The table below provides a reconciliation of income tax expense computed at the federal statutory income tax rate to the income tax provision from continuing operations.

	Years ended December 31,		
	2010	2009	2008
Income from continuing operations before income taxes	\$1,532	\$1,620	\$1,246
Net income attributable to noncontrolling interests in the Big 4 projects	—	(94)	(170)
Adjusted income from continuing operations before income taxes	\$1,532	\$1,526	\$1,076
Provision for income tax at federal statutory rate of 35%	\$536	\$534	\$377
Increase (decrease) in income tax from:			
Items presented with related state income tax, net			
Global settlement related	(95)	(306)	—
Change in tax accounting method for asset removal costs ¹	(40)	—	—
State tax – net of federal benefit	59	67	37
Health care legislation ²	39	—	—
Property-related and other	(59)	(46)	(72)
Total income tax expense from continuing operations	\$440	\$249	\$342
Effective tax rate	28.7%	16.3%	31.8%

¹ During the second quarter of 2010, the IRS approved SCE's request to change its tax accounting method for asset removal costs primarily related to its infrastructure replacement program. As a result, SCE recognized a \$40 million earnings benefit (of which \$28 million relates to asset removal costs incurred prior to 2010) from deducting asset removal costs earlier in the construction cycle. These deductions are recorded on a flow-through basis.

² During the first quarter of 2010, SCE recorded a \$39 million non-cash charge to reverse previously recognized federal tax benefits eliminated by the federal health care legislation enacted in March 2010. The Patient Protection and Affordable Care Act, as modified by the Health Care and Education Reconciliation Act, includes a provision that eliminates the federal tax deduction for retiree health care costs to the extent those costs are eligible for federal Medicare Part D subsidies. Although this change does not take effect until January 1, 2013, SCE is required to recognize the full accounting impact of the legislation in its financial statements in the period of enactment.

The CPUC requires flow-through ratemaking treatment for the current tax benefit arising from certain property-related and other temporary differences which reverse over time. The accounting treatment for these temporary differences results in recording regulatory assets and liabilities for amounts that would otherwise be recorded to deferred income tax expense.

Global Settlement

Edison International and the IRS finalized the terms of a Global Settlement on May 5, 2009. The Global Settlement resolved all of SCE's federal income tax disputes and affirmative claims through tax year 2002. During 2009, SCE recorded after-tax earnings of approximately \$306 million. During 2010, SCE recorded a \$95 million earnings benefit from the acceptance by the California Franchise Tax Board of the IRS tax positions finalized in 2009 and a revision to interest recorded on the federal Global Settlement. The net cash impacts of the Global Settlement, including the state impact, was \$26 million and \$875 million in 2010 and 2009, respectively.

Accounting for Uncertainty in Income Taxes

Authoritative guidance related to accounting for uncertainty in income taxes requires an enterprise to recognize, in its financial statements, the best estimate of the impact of a tax position by determining if the weight of the available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained on audit. The guidance requires the disclosure of all unrecognized tax benefits, which includes both the reserves recorded for tax positions on filed tax returns and the unrecognized

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portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

<u>(in millions)</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
Balance at January 1	\$482	\$2,066	\$1,950
Tax positions taken during the current year			
Increases	47	14	111
Tax positions taken during a prior year			
Increases	140	200	162
Decreases	(272)	(212)	(157)
Decreases for settlements during the period	(68)	(1,586)	—
Balance at December 31	<u>\$329</u>	<u>\$482</u>	<u>\$2,066</u>

Unrecognized tax benefits were reduced by \$68 million during 2010 related to the California Franchise Tax Board's acceptance of the federal Global Settlement as discussed above and \$1.6 billion during 2009 primarily due to completion of the federal Global Settlement as discussed above.

Edison International's federal income tax returns and its California combined franchise tax returns are currently open for years subsequent to 2002. In addition, specific California refund claims made by Edison International for years 1991 through 2002 remain subject to audit. The IRS examination phase of tax years 2003 through 2006 was completed in the fourth quarter of 2010, which included a proposed adjustment to disallow a component of SCE's repair allowance deduction. Edison International disagrees with the proposed adjustment and filed a protest with the IRS on January 28, 2011. If sustained, the proposed disallowance would result in a federal tax payment of \$90 million, including interest.

During the fourth quarter of 2010, SCE made a tax and interest deposit of \$131 million primarily related to rollforward issues included in the Global Settlement that subsequently impacted tax years 2003 through 2006.

As of December 31, 2010 and 2009, respectively, if recognized, \$225 million and \$179 million of the unrecognized tax benefits would impact the effective tax rate.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to SCE's income tax liabilities was \$61 million and \$79 million as of December 31, 2010 and 2009, respectively.

The net after-tax interest and penalties recognized in income tax expense was a benefit of \$80 million and \$279 million in 2010 and 2009, respectively, compared to an expense of \$14 million in 2008.

Fair Value Measurements

Recurring Fair Value Measurements

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (referred to as an "exit price"). Fair value of an asset or liability should consider assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk.

SCE categorizes financial assets and liabilities into a fair value hierarchy based on valuation inputs used to derive fair value. The hierarchy gives the highest priority to unadjusted quoted market prices in active markets for identical assets and liabilities (Level 1 measurements) and the lowest priority to unobservable inputs (Level 3 measurements).

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The following table sets forth assets and liabilities that were accounted for at fair value by level within the fair value hierarchy:

(in millions)	As of December 31, 2010				
	Level 1	Level 2	Level 3	Netting and Collateral ¹	Total
Assets at Fair Value					
Money market funds ²	\$243	\$—	\$—	\$—	\$243
Derivative contracts:					
Electricity	—	—	119	—	119
Natural gas	—	69	11	—	80
CRRs	—	—	137	—	137
Tolling	—	—	118	—	118
Subtotal of derivative contracts	—	69	385	—	454
Long-term disability plan	9	—	—	—	9
Nuclear decommissioning trusts					
Stocks ³	2,029	—	—	—	2,029
Municipal bonds	—	790	—	—	790
Corporate bonds ⁴	—	346	—	—	346
U.S. government and agency securities	215	73	—	—	288
Short-term investments, primarily cash equivalents ⁵	1	31	—	—	32
Sub-total of nuclear decommissioning trusts	2,245	1,240	—	—	3,485
Total assets ⁶	2,497	1,309	385	—	4,191
Liabilities at Fair Value					
Derivative contracts:					
Electricity	—	1	24	—	25
Natural gas	—	285	11	(4)	292
Tolling	—	—	344	—	344
Subtotal of derivative contracts	—	286	379	(4)	661
Total liabilities	—	286	379	(4)	661
Net assets	\$2,497	\$1,023	\$6	\$4	\$3,530

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(in millions)	As of December 31, 2009				
	Level 1	Level 2	Level 3	Netting and Collateral ¹	Total
Assets at Fair Value					
Money market funds ²	\$360	\$—	\$—	\$—	\$360
Derivative contracts:					
Electricity	—	—	1	—	1
Natural gas	—	10	76	—	86
CRRs	—	—	217	—	217
Tolling	—	—	43	—	43
Subtotal of derivative contracts	—	10	337	—	347
Long-term disability plan	8	—	—	—	8
Nuclear decommissioning trusts					
Stocks ³	1,772	—	—	—	1,772
Municipal bonds	—	634	—	—	634
Corporate bonds ⁴	—	393	—	—	393
U.S. government and agency securities	240	68	—	—	308
Short-term investments, primarily cash equivalents ⁵	1	14	—	—	15
Sub-total of nuclear decommissioning trusts	2,013	1,109	—	—	3,122
Total assets ⁶	2,381	1,119	337	—	3,837
Liabilities at Fair Value					
Derivative contracts:					
Electricity	—	—	25	—	25
Natural gas	—	150	21	—	171
Tolling	—	—	402	—	402
Subtotal of derivative contracts	—	150	448	—	598
Total liabilities	—	150	448	—	598
Net assets (liabilities)	\$2,381	\$969	\$(111)	\$—	\$3,239

1 Represents cash collateral and the impact of netting across the levels of the fair value hierarchy. Netting among positions classified within the same level is included in that level.

2 Included in cash and cash equivalents on SCE's consolidated balance sheets.

3 Approximately 67% of the equity investments were located in the United States at both December 31, 2010 and 2009.

4 Corporate bonds are diversified, and included \$27 million and \$50 million at December 31, 2010 and 2009, respectively, for collateralized mortgage obligations and other asset backed securities.

5 Excludes net liabilities of \$5 million and net assets of \$18 million at December 31, 2010 and 2009, respectively, of interest and dividend receivables and receivables related to pending securities sales and payables related to pending securities purchases.

6 Excludes \$31 million and \$32 million at December 31, 2010 and 2009, respectively, of cash surrender value of life insurance investments for deferred compensation.

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The following table sets forth a summary of changes in the fair value of Level 3 assets and liabilities:

(in millions)	December 31,	
	2010	2009
Fair value of derivative contracts, net liabilities at beginning of period	\$(111)	\$(518)
Total realized/unrealized gains, net:		
Included in regulatory assets and liabilities ¹	58	312
Purchases and settlements, net	43	70
Transfers into Level 3	—	—
Transfers out of Level 3	16	25
Fair value of derivative contracts, net assets (liabilities) at end of period	\$6	\$(111)
Change during the period in unrealized gains related to assets and liabilities held at the end of period	\$130	\$385

¹ Due to regulatory mechanisms, SCE's realized and unrealized gains and losses are recorded as regulatory assets and liabilities.

SCE determines the fair value for transfers in and transfers out of each level at the end of each reporting period. There were no significant transfers between levels during 2010 and 2009.

Valuation Techniques Used to Determine Fair Value

Level 1

Includes assets and liabilities where fair value is determined using unadjusted quoted prices in active markets that are available at the measurement date for identical assets and liabilities. Financial assets and liabilities classified as Level 1 include exchange-traded equity securities, exchange traded derivatives, U.S. treasury securities and money market funds.

Level 2

Pricing inputs include quoted prices for similar assets and liabilities in active markets and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the derivative instrument. Financial assets and liabilities utilizing Level 2 inputs include fixed-income securities and over-the-counter derivatives.

Derivative contracts that are over-the-counter traded are valued using pricing models to determine the net present value of estimated future cash flows and are generally classified as Level 2. Inputs to the pricing models include forward published or posted clearing prices from exchanges (New York Mercantile Exchange and Intercontinental Exchange) for similar instruments and discount rates. A primary source that best represents traded activity for each market is used to develop observable forward market prices in determining the fair value of these positions. Broker quotes or prices from exchanges are used to validate and corroborate the primary source. These price quotations reflect mid-market prices (average of bid and ask) and are obtained from sources believed to provide the most liquid market for the commodity. Broker quotes are incorporated when corroborated with other information which may include a combination of prices from exchanges, other brokers and comparison to executed trades.

Level 3

Includes financial asset and liabilities where fair value is determined using techniques that require significant unobservable inputs. Over-the-counter options, bilateral contracts, capacity contracts, QF contracts, derivative contracts that trade infrequently (such as congestion revenue rights ("CRRs") in the California market and over-the-counter derivatives at illiquid locations), long-term power agreements, and derivative contracts with counterparties that have significant nonperformance risks are generally valued using pricing models that incorporate unobservable inputs and are classified as Level 3. Assumptions are made in order to value derivative contracts in which observable inputs are not available. In circumstances where SCE cannot verify fair value with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. As markets continue to

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develop and more pricing information becomes available, SCE continues to assess valuation methodologies used to determine fair value.

For derivative contracts that trade infrequently (illiquid financial transmission rights and CRRs), changes in fair value are based on models forecasting the value of those contracts. The models' inputs are reviewed and the fair value is adjusted when it is concluded that a change in inputs would result in a new valuation that better reflects the fair value of those derivative contracts. For illiquid long-term power agreements, fair value is based upon the discounting of future electricity and natural gas prices derived from a proprietary model using the risk free discount rate for a similar duration contract, adjusted for credit risk and market liquidity. Changes in fair value are based on changes to forward market prices, including forecasted prices for illiquid forward periods. The fair value of the majority of SCE's derivatives that are classified as Level 3 is determined using uncorroborated non-binding broker quotes and models which may require SCE to extrapolate short-term observable inputs in order to calculate fair value. Broker quotes are obtained from several brokers and compared against each other for reasonableness.

Nonperformance Risk

The fair value of the derivative assets and liabilities are adjusted for nonperformance risk. To assess nonperformance risks, SCE considers the probability of and the estimated loss incurred if a party to the transaction were to default. SCE also considers collateral, netting arrangements, guarantees and other forms of credit support when assessing nonperformance. The nonperformance risk adjustment represented an insignificant amount at both December 31, 2010 and 2009.

Nuclear Decommissioning Trusts

The SCE nuclear decommissioning trust investments include equity securities, U.S. treasury securities and other fixed-income securities. Equity and treasury securities are classified as Level 1 as fair value is determined by observable market prices in active or highly liquid and transparent markets. The remaining fixed-income securities are classified as Level 2. The fair value of these financial instruments is based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes, issuer spreads, bids, offers and relevant credit information.

Future nuclear decommissioning costs of removal of nuclear assets are expected to be funded from independent decommissioning trusts, which currently receive contributions of approximately \$23 million per year included in SCE customer rates. Contributions to the decommissioning trusts are reviewed every three years by the CPUC. If additional funds are needed for decommissioning, it is probable that the additional funds will be recoverable through customer rates. Funds collected, together with accumulated earnings, will be utilized solely for decommissioning. The CPUC has set certain restrictions related to the investments of these trusts.

The following table sets forth amortized cost and fair value of the trust investments:

(in millions)	Longest Maturity Dates	Amortized Cost		Fair Value	
		December 31,		December 31,	
		2010	2009	2010	2009
Stocks	—	\$895	\$822	\$2,029	\$1,772
Municipal bonds	2049	706	545	790	634
Corporate bonds	2044	288	309	346	393
U.S. government and agency securities	2040	270	287	288	308
Short-term investments and receivables/payables	One-year	26	33	27	33
Total		\$2,185	\$1,996	\$3,480	\$3,140

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Proceeds from sales of securities (which are reinvested) were \$1.4 billion, \$2.2 billion and \$3.1 billion for the years ended December 31, 2010, 2009 and 2008, respectively. Unrealized holding gains, net of losses, were \$1.3 billion and \$1.1 billion at December 31, 2010 and 2009, respectively. Approximately 92% of the cumulative trust fund contributions were tax-deductible.

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The following table sets forth a summary of changes in the fair value of the trust for the years ended December 31:

(in millions)	2010	2009	2008
Balance at beginning of period	\$3,140	\$2,524	\$3,378
Realized gains (losses) – net	121	95	(65)
Unrealized gains (losses) – net	148	526	(545)
Other-than-temporary impairments	(27)	(111)	(317)
Interest, dividends, contributions and other	98	106	73
Balance at end of period	\$3,480	\$3,140	\$2,524

Due to regulatory mechanisms, earnings and realized gains and losses (including other-than-temporary impairments) have no impact on operating revenue or earnings.

Fair Value of Long-Term Debt Recorded at Carrying Value

The carrying amounts and fair values of long-term debt are:

(in millions)	December 31,			
	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	\$7,627	\$8,285	\$6,740	\$7,202

Fair values of long-term debt are based on evaluated prices that reflect significant observable market information such as reported trades, actual trade information of similar securities, benchmark yields, broker/dealer quotes of new issue prices and relevant credit information.

The carrying value of trade receivables, payables and short-term debt approximates fair value and therefore are not included in the table above.

Power Purchase Agreements

SCE, generally as the purchaser, enters into long-term power purchase agreements in the normal course of business. Accounting for long-term power purchase agreements is complex and varies based on the terms and conditions of each agreement. A power purchase agreement may be considered a variable interest in a variable interest entity. Under this classification, the power purchase agreement is evaluated to determine if it is the primary beneficiary in the variable interest entity, in which case, such entity would be consolidated. None of SCE's contracts resulted in consolidation of a variable interest entity at December 31, 2010.

A power purchase agreement may also contain a lease for accounting purposes. This generally occurs when a power purchase agreement (signed or modified after June 30, 2003) designates a specific power plant in which the buyer purchases substantially all of the output and does not otherwise meet a fixed price per unit of output exception. SCE has a number of power purchase agreements that contain leases. SCE's recognition of lease expense conforms to the ratemaking treatment for SCE's recovery of the cost of electricity.

A power purchase agreement that does not contain a lease may be classified as a derivative. SCE records its derivative instruments on its consolidated balance sheets at fair value unless they qualify for the normal purchase and sale exception, in which case, the power purchase agreement is classified as an executory contract. Most of SCE's QF contracts are not required to be recorded on the consolidated balance sheets because they either do not meet the definition of a derivative or meet the normal purchase and sale exception. However, SCE purchases power from certain QFs in which the contract pricing is based on a normal gas index, but the

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power is not generated with natural gas. These contracts are not eligible for the normal purchase and sale exception and are recorded as a derivative on the consolidated balance sheets at fair value.

Power purchase agreements that do not meet the above classifications are accounted for on the accrual basis.

Regulatory and Environmental Developments

Regulatory Developments

Wildfire Insurance Issues

Severe wildfires in California have given rise to large damage claims against California utilities for fire-related losses alleged to be the result of the failure of electric and other utility equipment. Invoking a California Court of Appeal decision, plaintiffs pursuing these claims have relied on the doctrine of inverse condemnation, which can impose strict liability (including liability for a claimant's attorneys' fees) for property damage. On September 1, 2010, SCE's parent, Edison International, renewed its insurance coverage, which included coverage for SCE's wildfire liabilities up to a \$610 million limit (with an increased self-insured retention of \$10 million per wildfire occurrence). Various coverage limitations within the policies that make up the insurance coverage could result in additional self-insured costs in the event of multiple wildfire occurrences during the policy period (September 1, 2010 to August 31, 2011). SCE may experience coverage reductions and/or increased insurance costs in future years. No assurance can be given that future losses will not exceed the limits of SCE's insurance coverage.

Environmental Developments

SCE is subject to numerous environmental laws and regulations, which typically require a lengthy and complex process for obtaining licenses, permits and approvals and require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate the environmental impact of past operations.

Possible developments, such as the enactment of more stringent environmental laws and regulations, proceedings that may be initiated by environmental and other regulatory authorities, cases in which new theories of liability are recognized, and settlements agreed to by other companies that establish precedent or expectations for the power industry, could affect the costs and the manner in which business is conducted, and could cause substantial additional capital expenditures or operational expenditures or the ceasing of operations at certain facilities. There is no assurance that any additional costs arising from such developments would be recovered from customers or that SCE's financial position, results of operations and cash flows would not be materially affected by these developments.

Greenhouse Gas Regulation

There have been a number of federal and state legislative and regulatory initiatives to reduce greenhouse gas ("GHG") emissions. Any climate change regulation or other legal obligation that would require substantial reductions in GHG emissions or that would impose additional costs or charges for GHG emissions could significantly increase the cost of generating electricity from fossil fuels as well as the cost of purchased power, which could adversely affect SCE's business. In the case of utilities, like SCE, these costs are generally borne by customers.

Significant developments include the following:

- In December 2009, the US EPA issued a final finding that certain GHGs, including carbon dioxide, threaten the public health and welfare. The US EPA has issued a proposed rule, known as the "GHG tailoring rule," which generally subjects newly constructed sources of GHG emissions and newly modified existing major sources to the Prevention of Significant Deterioration air permitting program (and later, the Title V permitting program), beginning in January 2011. The current program, which applies to only new or newly modified sources, is not expected to have an immediate effect on SCE's existing generating plants. However, regulation of GHG emissions pursuant to this program could affect efforts to modify SCE's facilities in the future, and could subject new capital projects to additional permitting and pollution control requirements that could delay such projects.

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- Under a pending court settlement, the US EPA will propose performance standards for GHG emissions from new and modified power plants, and emissions guidelines for existing power plants, in July 2011, and will finalize such regulations by May 2012, with compliance dates expected to be in 2015 or 2016. The specific requirements will not be known until the regulations are finalized.
- In December 2010, the California Air Resources Board (“CARB”) finalized regulations establishing a California cap-and-trade program, which include revisions to CARB’s mandatory GHG emissions reporting regulation. The regulations and the cap-and-trade program itself are being challenged by various citizens’ groups under the California Environmental Quality Act.
- In December 2010, the Supreme Court agreed to hear a case in which an appellate court found that judicial remedies for nuisance allegedly caused by GHG emissions were appropriate. The Supreme Court’s decision may resolve the question of whether or not this type of litigation presents questions capable of judicial resolution or political questions that should be resolved by elected officials.

Clean Water Act

Regulations under the federal Clean Water Act govern critical parameters at generating facilities, such as the temperature of effluent discharges and the location, design, and construction of cooling water intake structures at generating facilities. The US EPA is rewriting these regulations following a 2009 U.S. Supreme Court decision that held that the US EPA may consider, but is not required to use, a cost-benefit analysis for this purpose. The Supreme Court set a deadline of March 2011 for draft regulations, which are to be finalized by July 2011. The new regulations will not allow the use of restoration to achieve compliance, but it is unknown whether they will use a cost-benefit analysis for determining the best technology available for compliance.

A new rule could have a material impact on SCE’s operations but SCE cannot determine the financial impact until the final compliance criteria have been published. Significant capital expenditures may be required.

Once-Through Cooling

California has a US EPA-approved program to issue individual or group (general) permits for the regulation of Clean Water Act discharges. California also regulates certain discharges not regulated by the US EPA. In May 2010, the California State Water Resources Board issued a final policy, which establishes closed-cycle wet cooling as required technology for retrofitting existing once-through cooled plants like San Onofre and many of the existing fossil-fueled power plants along the California coast. The final policy, which took effect on October 1, 2010, requires an independent engineering study to be completed prior to the fourth quarter of 2013 regarding the feasibility of compliance by California’s two coastal nuclear power plants. Depending on the results of the study, the required compliance may result in significant capital expenditures at San Onofre and may affect its operations. The policy could adversely affect California’s nineteen once-through cooled power plants, which provide over 21,000 MW of combined, in-state generation capacity, including over 9,100 MW of capacity interconnected within SCE’s service territory. The policy may also significantly impact SCE’s ability to procure generating capacity from fossil-fueled plants that use ocean water in once-through cooling systems, system reliability and the cost of electricity to the extent other coastal power plants in California are forced to shut down or limit operations.

New Accounting Guidance

Accounting Guidance Adopted in 2010

Consolidation—Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities

This Financial Accounting Standards Board (“FASB”) update changes how a company determines when an entity, that is insufficiently capitalized or is not controlled through voting (or similar rights), should be consolidated. The determination of whether a company is required to consolidate an entity is based on, among other things, its ability to direct the activities of the entity that most significantly impact the entity’s economic performance and whether the entity has an obligation to absorb losses or the right to receive expected returns of the entity. This guidance requires a company to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. SCE adopted this guidance prospectively effective

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January 1, 2010. The impact of adopting this guidance resulted in the deconsolidation of projects related to four QF contracts for GAAP reporting.

Fair Value Measurements and Disclosures

This FASB accounting standards update provides for new disclosure requirements related to fair value measurements. The requirements, which SCE adopted effective January 1, 2010, include separate disclosure of significant transfers in and out of Levels 1 and 2 and the reasons for the transfers. The update also clarified existing disclosure requirements for the level of disaggregation, inputs and valuation techniques. Since this guidance impacts disclosures only, the adoption did not have an impact on SCE's consolidated results of operations, financial position or cash flows. In addition, effective January 1, 2011, the Level 3 reconciliation of fair value measurements using significant unobservable inputs should include gross rather than net information about purchases, sales, issuances and settlements. The guidance impacts disclosures only.

BALANCE SHEET:

Allowance for Uncollectible Accounts

SCE records an allowance for uncollectible accounts, generally determined by the average percentage of amounts written-off in prior periods. Generally, SCE assesses its customers a late fee of 0.9% per month, beginning 21 days after the bill is prepared. Inactive accounts are written off after 180 days.

Cash Equivalents

Cash equivalents included investments in money market funds totaling \$243 million and \$360 million at December 31, 2010 and 2009, respectively. Generally, the carrying value of cash equivalents equals the fair value, as all investments have maturities of three months or less.

SCE temporarily invests the ending daily cash balance in its primary disbursement accounts until required for check clearing. SCE reclassified \$196 million and \$224 million of checks issued against these accounts, but not yet paid by the financial institution, from cash to accounts payable at December 31, 2010 and 2009, respectively.

Inventory

Inventory is stated at the lower of cost or market, cost being determined by the average cost method for fuel and materials and supplies.

Preferred and Preference Stock

The Series A and B preference stock were issued in 2005 and the Series C preference stock was issued in 2006. SCE may, at its option, redeem the Series A, B, or C preference stock in whole or in part. No preference stock was redeemed in the last three years.

At December 31, 2010 accrued dividends related to SCE's preferred and preference stock were \$13 million.

Property, Plant and Equipment

Utility Property, Plant and Equipment

Utility plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead, a portion of administrative and general costs capitalized at a rate authorized by the CPUC, and AFUDC.

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AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction and is capitalized during certain plant construction. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset.

AFUDC – equity represents a method to compensate SCE for the estimated cost of equity used to finance utility plant additions and is recorded as part of construction in progress. AFUDC – equity was \$100 million, \$116 million and \$54 million in 2010, 2009 and 2008, respectively. AFUDC – debt was \$41 million, \$32 million and \$27 million in 2010, 2009 and 2008, respectively.

The FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the construction phase (referred to as CWIP) and recovery of abandoned plant costs for several of SCE’s transmission projects. In addition, the FERC granted an incentive for CAISO participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the three projects and earn a return on equity, rather than capitalizing AFUDC.

If SCE had not implemented this transmission incentive mechanism, and continued to follow the FERC Uniform System of accounts for these costs, the AFUDC amount would have been approximately \$59 million and \$20 million as of December 31, 2010 and 2009, respectively. The following is a partial balance sheet that includes the amounts not capitalized because of the transmission rate incentives:

(in millions)	December 31,	
	2010	2009
Utility property, plant and equipment	\$33,526	\$31,019
Construction work in progress	3,347	2,725
Total utility property, plant and equipment	36,873	33,744
(Less) accumulated provision for depreciation, amortization and depletion	(14,997)	(14,554)
Net utility property, plant and equipment	21,876	19,190

In May 2003, the Palo Verde units returned to traditional cost-of-service ratemaking while San Onofre Units 2 and 3 returned to traditional cost-of-service ratemaking in January 2004. SCE’s nuclear plant investments made prior to the return to cost-of-service ratemaking are recorded as regulatory assets. Since the return to cost-of-service ratemaking, capital additions are recorded in utility plant. These classifications do not affect the ratemaking treatment for these assets.

Estimated useful lives (authorized by the CPUC) and weighted-average useful lives of SCE’s property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	25 years to 70 years	40 years
Distribution plant	30 years to 60 years	40 years
Transmission plant	35 years to 65 years	46 years
Other plant	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 4.1%, 4.2% and 4.3% for 2010, 2009 and 2008, respectively. Replaced or retired property costs are charged to the accumulated provision for depreciation. Cash payments for removal costs less salvage reduce the liability for AROs.

Nuclear fuel is recorded as utility plant (nuclear fuel in the fabrication and installation phase is recorded as construction in progress) in accordance with CPUC ratemaking procedures. Nuclear fuel is amortized using the units of production method.

During 2009, the CPUC and FERC authorized the transfer of the Mountainview power plant to utility rate base which resulted in a one time, non-cash accounting benefit of approximately \$46 million. This non-cash accounting benefit primarily resulted from the establishment of regulatory assets to recognize \$50 million in differences in the accounting treatment for non-regulated and rate-regulated entities mainly related to equity AFUDC. There was no economic impact to customers from this change as compared to

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the FERC-approved power-purchase agreement. The transfer resulted in a \$603 million increase in SCE's utility property, plant and equipment.

Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's proportionate share of these projects is reflected in the consolidated balance sheets and included in the above table. SCE's proportionate share of expenses for each project is reflected in the consolidated statements of income.

The following is SCE's investment in each project as of December 31, 2010:

(in millions)	Investment in Facility	Accumulated Depreciation and Amortization	Ownership Interest
Transmission systems:			
Eldorado	\$74	\$12	60%
Pacific Intertie	183	65	50
Generating stations:			
Four Corners Units 4 and 5 (coal)	596	499	48
Mohave (coal)	347	312	56
Palo Verde (nuclear)	1,899	1,543	16
San Onofre (nuclear)	5,369	4,080	78
Total	\$8,468	\$6,511	

All of the investments in the Mohave generating station and a portion of the investments in San Onofre and Palo Verde generating stations are included in regulatory assets on the consolidated balance sheets.

On November 8, 2010, SCE entered into an agreement to sell its ownership interest in Units 4 and 5 of the Four Corners coal-fired electric generating facility to the operator of the facility, Arizona Public Service Company. The sale price is \$294 million, subject to certain adjustments. The closing of the sale is contingent upon the receipt of regulatory approvals and other specified closing conditions and is currently estimated to occur in the second half of 2012. Any gain on the sale will be for the benefit of SCE's ratepayers and, therefore, will not affect SCE's earnings.

Asset Retirement Obligation

The fair value of a liability for an asset retirement obligation ("ARO") is recorded in the period in which it is incurred, including a liability for the fair value of a conditional ARO, if the fair value can be reasonably estimated even though uncertainty exists about the timing and/or method of settlement. When an ARO liability is initially recorded, the entity capitalizes the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is increased for accretion expense each period and the capitalized cost is depreciated over the useful life of the related asset. Settlement of an ARO liability for an amount other than its recorded amount results in an increase or decrease in expense. AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies. Those site-specific studies are updated with each Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP"). The initial establishment of a nuclear-related ARO is at fair value. Subsequent layers of an ARO are established for

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updated site-specific decommissioning cost estimates stemming from the approved NDCTP. A reconciliation of the changes in the ARO liability is as follows:

<u>(in millions)</u>	<u>2010</u>	<u>2009</u>	<u>2008</u>
Beginning balance	\$3,198	\$3,007	\$2,877
Accretion expense	195	186	175
Revisions ¹	(867)	6	(10)
Liabilities settled	(1)	(1)	(35)
Transfers in or out ²	(18)	—	—
Ending balance	<u>\$2,507</u>	<u>\$3,198</u>	<u>\$3,007</u>

1 Revisions represent the most recent site-specific studies approved by the CPUC in 2010.

2 Transfers in or out consist of the deconsolidation of the Big 4 projects effective January 1, 2010.

The ARO liability as of December 31, 2010 includes \$2.4 billion related to nuclear decommissioning.

Impairment of Long-Lived Assets

SCE evaluates the impairment of its long-lived assets based on a review of estimated future cash flows expected to be generated whenever events or changes in circumstances indicate that the carrying amount of such investments or assets may not be recoverable. If the carrying amount of a long-lived asset exceeds expected future cash flows, undiscounted and without interest charges, an impairment loss is recognized in the amount of the excess of fair value over the carrying amount. SCE's impaired assets are recorded as a regulatory asset if it is deemed probable that such amounts will be recovered from ratepayers.

Debt and Credit Agreements

Long-Term Debt

In 2009, SCE purchased two issues of its tax-exempt bonds totaling \$219 million that were subject to remarketing and also converted those issues to a variable rate structure. In 2010, SCE reissued \$144 million of these bonds and continues to hold the remaining \$75 million of these bonds which remain outstanding and have not been retired or cancelled.

Long-term debt maturities for the next five years are: 2011 – zero; 2012 – zero; 2013 – zero; 2014 – \$1.1 billion; and 2015 – \$308 million.

Liens and Security Interests

Almost all SCE properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from certain pollution-control bonds issued by government agencies. SCE has a debt covenant that requires a debt to total capitalization ratio be met. At December 31, 2010, SCE was in compliance with this debt covenant.

Credit Agreements

SCE has two revolving credit facilities with various banks; a \$2.4 billion five-year credit facility that terminates in February 2013, with four one-year options to extend by mutual consent, and a \$500 million three-year credit facility that terminates in March 2013. Borrowings under these credit facilities are generally used to finance fuel inventories, balancing accounts undercollections and general, temporary cash requirements including power purchase payments. At December 31, 2010, letters of credit issued under SCE's credit facilities are scheduled to expire in twelve months or less.

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The following table summarizes the status of SCE's credit facilities at December 31, 2010:

<u>(in millions)</u>	<u>Credit Facilities</u>
Commitment	\$2,894
Outstanding borrowings	—
Outstanding letters of credit	(24)
Amount available	<u>\$2,870</u>

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis as interest expense over the term of the related debt. Under CPUC ratemaking procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt. SCE had unamortized losses on reacquired debt of \$268 million and \$287 million at December 31, 2010 and 2009, respectively, reflected in "Regulatory assets" in the long-term section of the consolidated balance sheets. SCE had unamortized debt issuance costs of \$60 million and \$50 million at December 31, 2010 and 2009, respectively, reflected in "Other long-term assets" on the consolidated balance sheets. Amortization of deferred financing costs charged to interest expense was \$30 million, \$27 million and \$26 million in 2010, 2009 and 2008, respectively.

Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. Sales balancing accounts accumulate differences between recorded electric utility revenue and revenue SCE is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs SCE is authorized to recover through rates. Under-collections are recorded as regulatory balancing account assets. Over-collections are recorded as regulatory balancing account liabilities. SCE's regulatory balancing accounts accumulate balances until they are refunded to or received from SCE's customers through authorized rate adjustments. Primarily all of SCE's balancing accounts can be classified as one of the following types: generation-revenue related, distribution-revenue related, generation-cost related, distribution-cost related, transmission-cost related or public purpose and other cost related.

Balancing account under-collections and over-collections accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

Amounts included in regulatory assets and liabilities are generally recorded with corresponding offsets to the applicable income statement accounts.

Regulatory Assets

SCE's regulatory assets related to energy derivatives are primarily an offset to unrealized losses on derivatives. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its net regulatory assets related to income taxes over the life of the assets that give rise to the accumulated deferred income taxes. SCE's regulatory assets related to pensions and other post-retirement plans represents the recoverable portion of the additional amounts recorded in accordance with authoritative guidance on accounting for pensions and post-retirement plans. This amount will be recovered through rates charged to customers. SCE's unamortized generation investment includes nuclear assets related to San Onofre which are expected to be recovered by 2022, nuclear assets related to Palo Verde which are expected to be recovered by 2027 and SCE's unamortized coal plant investment which is being recovered through June 2016. Unamortized distribution investment includes legacy meters retired as part of the EdisonSmartConnect™ program which are expected to be recovered by 2025. Although SCE's unamortized generation and distribution investments are classified as regulatory assets on the consolidated balance sheets, they continue to be a component of rate base and earned an 8.75% return in both

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2010 and 2009. SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from one year to 28 years.

Regulatory Liabilities

SCE's regulatory liability related to the ARO represents timing differences between the ARO and the assets of the nuclear decommissioning trust. The balance varies due to changes in the ARO as well as nuclear decommissioning trust investment activities. SCE's regulatory liabilities related to costs of removal represent operating revenue collected for asset removal costs that SCE expects to incur in the future. These balances will be returned to ratepayers in a future ratemaking proceeding, be charged against expense to the extent that future expenses exceed amounts recoverable through the ratemaking process, or be applied as otherwise directed by the CPUC.

Dividend Restrictions

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC sets an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay \$497 million in additional dividends.

Related Party Transactions

Specified administrative services such as payroll and employee benefit programs, performed by SCE employees, are shared among all subsidiaries of Edison International, and the cost of these corporate support services are allocated to all subsidiaries. Costs are allocated based on one of the following formulas: relative amount of equity in investment, number of employees, or multi-factor method (operating revenue, operating expenses, total assets and number of employees). In addition, services of SCE employees are sometimes directly requested by an Edison International subsidiary and these services are performed for the subsidiary's benefit. Labor and expenses of these directly requested services are specifically identified and billed at cost. SCE participates in the insurance program of Edison International, including property, general liability, workers' compensation and various other specialty policies. SCE's insurance premiums are generally based on SCE's share of risk related to each policy.

Accumulated Other Comprehensive Loss

SCE's accumulated other comprehensive income consists of:

(in millions)	Pension and PBOP – Net Loss	Pension and PBOP – Prior Service Cost	Accumulated Other Comprehensive Loss
Balance at December 31, 2008	(13)	(1)	(14)
Change for 2009	(5)	—	(5)
Balance at December 31, 2009	(18)	(1)	(19)
Change for 2010	(7)	1	(6)
Balance at December 31, 2010	(25)	\$—	(25)

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INCOME STATEMENT:

Other Income and Expenses

Other income and expenses are as follows:

(in millions)	Years ended December 31,		
	2010	2009	2008
Other income:			
Equity AFUDC	\$100	\$116	\$54
Increase in cash surrender value of life insurance policies	25	23	24
Energy settlement	5	9	3
Other	11	12	20
Total other income	<u>\$141</u>	<u>\$160</u>	<u>\$101</u>
Other expenses:			
Penalties	\$—	\$—	\$59
Civic, political and related activities and donations	28	28	34
Marketing services	7	11	11
Other	16	10	19
Total other expenses	<u>\$51</u>	<u>\$49</u>	<u>\$123</u>

The 2008 penalty primarily resulted from a CPUC decision in September 2008 related to SCE incentives claimed under a CPUC-approved PBR mechanism.

Major Maintenance

Certain plant facilities and equipment require periodic major maintenance. These costs are expensed as incurred.

Revenue Recognition

Operating revenue is recognized when electricity is delivered and includes amounts for services rendered but unbilled at the end of each reporting period. Rates charged to customers are based on CPUC-authorized and FERC-approved revenue requirements. CPUC rates are implemented upon final approval. FERC rates are often implemented on an interim basis at the time the rate change is filed. Revenue collected prior to a final FERC approval decision is subject to refund.

SCE recognizes revenue from base rates and cost-recovery rates, and could potentially recognize revenue or incur penalties under incentive mechanisms. Base rate activities provide for recovery of operation and maintenance costs, capital-related carrying costs and a return or profit, on a forecast basis, as well as a return on certain capital-related projects approved through balancing account mechanisms, separate from the GRC process. Cost-recovery rates provide for recovery for fuel, purchased power, demand-side management programs, nuclear decommissioning, public purpose programs, certain operation and maintenance expenses, and depreciation expense related to certain projects. There is no markup for return or profit for cost-recovery expenses (revenue recognized under cost-recovery rates is equal to expenses incurred under these mechanisms), except for a return on certain capital-related balancing account projects.

The CPUC-authorized decoupling revenue mechanisms allow differences in revenue resulting from actual and forecast volumetric electricity sales to be collected from or refunded to ratepayers; and therefore, such differences do not impact operating revenue. Differences between authorized operating costs included in SCE's base rate revenue requirement and actual operating costs incurred, other than pass-through costs, do not impact operating revenue, but have an impact on earnings.

Power purchased by the CDWR related to long-term contracts it executed on behalf of SCE's customers between January 17, 2001 and December 31, 2002 is not considered a cost to SCE because SCE is acting as an agent for these transactions. Furthermore, amounts billed to (\$1.2 billion, \$1.8 billion, and \$2.2 billion in 2010, 2009 and 2008, respectively) and collected from SCE's customers for these power purchases, CDWR bond-related costs (effective November 15, 2002 and expected to continue until 2022) and a portion of

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direct access exit fees (effective January 1, 2003 and expected to continue until 2022) are being remitted to the CDWR and are not recognized as operating revenue by SCE.

Sales and Use Taxes

SCE bills certain sales and use taxes levied by state or local governments to its customers. Included in these sales and use taxes are franchise fees, which SCE pays to various municipalities (based on contracts with these municipalities) in order to operate within the limits of the municipality. SCE bills these franchise fees to its customers based on a CPUC-authorized rate. These franchise fees, which are required to be paid regardless of SCE's ability to collect from the customer, are accounted for on a gross basis and reflected in operating revenue and other operation and maintenance expense. SCE's franchise fees billed to customers and recorded as operating revenue were \$102 million, \$102 million and \$103 million for the years ended December 31, 2010, 2009 and 2008, respectively. When SCE acts as an agent and when the tax is not required to be remitted as not having been collected from the customer, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are for remission to the taxing authorities and are not recognized as operating revenue.

CASH FLOW STATEMENT:

Supplemental Cash Flows Information

SCE's supplemental cash flows information is:

(in millions)	Years ended December 31,		
	2010	2009	2008
Cash payments(receipts) for interest and taxes:			
Interest – net of amounts capitalized	\$369	\$352	\$303
Tax payments (refunds) – net	(127)	(658)	251
Noncash investing and financing activities:			
Details of debt exchange:			
Pollution-control bonds redeemed	\$(378)	\$—	\$—
Pollution-control bonds issued	378	—	—
Details of capital lease obligations:			
Capital lease purchased	\$—	\$(223)	\$—
Capital lease obligation issued	—	223	—
Deconsolidation of variable interest entities:			
Assets other than cash	\$306	\$—	\$—
Liabilities and noncontrolling interests	(398)	—	—
Dividends declared but not paid:			
Common stock	\$—	\$100	\$100
Preferred and preference stock	13	13	13

Item 2. Significant Contingencies

Contingencies

In addition to the matters disclosed in these Notes, SCE is involved in other legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these other proceedings will not materially affect its results of operations or liquidity.

Navajo Nation Litigation

The Navajo Nation filed a complaint in June 1999 against SCE, among other defendants, arising out of the coal supply agreement for Mohave. Subsequently, the Hopi Tribe was added as an additional plaintiff. As amended in April 2010, the Navajo Nation's complaint asserts claims for, among other things, interference with fiduciary duties and contractual relations, fraudulent misrepresentations by

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nondisclosure, and various contract-related claims. The complaint claims that the defendants' actions prevented the Navajo Nation from obtaining the full value in royalty rates for the coal supplied to Mohave. The complaint seeks damages of not less than \$600 million, plus interest thereon, and punitive damages of not less than \$1 billion. No trial date has been set for this litigation. In April 2009, in a related case filed in December 1993 against the U.S. Government, the U.S. Supreme Court found that the Navajo Nation did not have a claim for compensation. In October 2010, the Hopi Tribe settled all of its claims and the remaining parties agreed to engage in mediation. SCE cannot predict the outcome of the Navajo Nation's complaint against SCE.

Environmental Remediation

SCE records its environmental remediation liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (reflected in "Other long-term liabilities") at undiscounted amounts as timing of cash flows is uncertain.

As of December 31, 2010, SCE's recorded estimated minimum liability to remediate its 23 identified material sites (sites in which the upper end of the range of costs is at least \$1 million) was \$50 million, of which \$20 million was related to San Onofre. In addition to its identified material sites SCE also has 34 immaterial sites for which the total recorded liability was \$4 million. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs at these identified material sites and immaterial sites could exceed its recorded liability by up to \$200 million and \$7 million, respectively. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover 90% of its environmental remediation costs at certain sites, representing \$29 million of its recorded liability, through an incentive mechanism (SCE may request to include additional sites). Under this mechanism, SCE recovers 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with all responsible carriers. SCE expects to recover costs incurred at its remaining sites through customer rates. SCE has recorded a regulatory asset of \$51 million for its estimated minimum environmental cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from \$3 million to \$18 million. Recorded costs were \$17 million, \$11 million and \$29 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range for its identified sites and, based upon the CPUC's regulatory treatment of environmental remediation costs, SCE believes that costs ultimately recorded will not materially affect its results of operations, financial position or cash flows. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

2010 FERC Rate Case

In February 2011, the FERC approved a settlement agreement in SCE's 2010 FERC rate case that provides a FERC retail base revenue requirement of \$490 million, an increase of \$42 million, or 9.4%, over the 2009 FERC base revenue requirement. The increased

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revenue requirement is primarily due to an increase in transmission capital investments and will be retroactive to March 1, 2010. As of December 31, 2010, SCE had collected revenue, subject to refund, of \$58 million that will be refunded to ratepayers. SCE did not previously recognize revenue for the amount that will be refunded.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to the amount of available financial protection, which is currently approximately \$12.6 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available (\$375 million). The balance is covered by a loss sharing program among nuclear reactor licensees. If a nuclear incident at any licensed reactor in the United States results in claims and/or costs which exceed the primary insurance at that plant site, all nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

Based on its ownership interests, SCE could be required to pay a maximum of approximately \$235 million per nuclear incident. However, it would have to pay no more than approximately \$35 million per incident in any one year. If the public liability limit above is insufficient, federal law contemplates that additional funds may be appropriated by Congress. This could include an additional assessment on all licensed reactor operators as a measure for raising further federal revenue.

Property damage insurance covers losses up to \$500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary \$500 million also has been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. A mutual insurance company owned by entities with nuclear facilities issues these policies. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to approximately \$43 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the Department of Energy (“DOE”) is responsible for the selection and construction of a facility for the permanent disposal of spent nuclear fuel and high-level radioactive waste. The DOE did not meet its contractual obligation to begin acceptance of spent nuclear fuel by January 31, 1998. Extended delays by the DOE have led to the construction of costly alternatives and associated siting and environmental issues. Currently, both San Onofre and Palo Verde have interim storage for spent nuclear fuel on site sufficient for the current license period.

In January 2004, SCE, as operating agent of San Onofre, filed a complaint against the DOE in the United States Court of Federal Claims seeking damages for the DOE’s failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. In June 2010, the United States Court of Federal Claims issued a decision granting SCE damages of approximately \$142 million to recover costs incurred through December 31, 2005, which has been appealed by the DOE. Additional legal action would be necessary to recover damages incurred after that date. Any damages recovered would be returned to SCE ratepayers or used to offset past or future fuel decommissioning or storage costs for the benefit of ratepayers.

Item 3.

N/A

Item 4.

There accounts are used where applicable. The balance for unamortized loss on reacquired debt (account number 189.100) at December 31, 2010 was approximately \$268 million. There is no unamortized gain (account number 257.XXX) recorded on the books at December 31, 2010.

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Item 5.

The CPUC regulates SCE's capital structure and limits the dividends it may pay Edison International. In SCE's most recent cost of capital proceeding, the CPUC set an authorized capital structure for SCE which included a common equity component of 48%. SCE may make distributions to Edison International as long as the common equity component of SCE's capital structure remains at or above the 48% authorized level on a 13-month weighted average basis. At December 31, 2010, SCE's 13-month weighted-average common equity component of total capitalization was 51% resulting in the capacity to pay \$497 million in additional dividends.

Item 6.

See response to Item 1 & 2 above.

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				(14,271,894)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,462,341
3	Preceding Quarter/Year to Date Changes in Fair Value				(6,918,248)
4	Total (lines 2 and 3)				(4,455,907)
5	Balance of Account 219 at End of Preceding Quarter/Year				(18,727,801)
6	Balance of Account 219 at Beginning of Current Year				(18,727,801)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,762,386
8	Current Quarter/Year to Date Changes in Fair Value				(8,721,910)
9	Total (lines 7 and 8)				(5,959,524)
10	Balance of Account 219 at End of Current Quarter/Year				(24,687,325)

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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			(14,271,894)		
2			2,462,341		
3			(6,918,248)		
4			(4,455,907)	1,276,920,169	1,272,464,262
5			(18,727,801)		
6			(18,727,801)		
7			2,762,386		
8			(8,721,910)		
9			(5,959,524)	1,091,619,871	1,085,660,347
10			(24,687,325)		

**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)	29,819,558,195	29,787,643,139
4	Property Under Capital Leases	226,737,085	226,737,085
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,453,003,868	3,453,003,868
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	33,499,299,148	33,467,384,092
9	Leased to Others		
10	Held for Future Use	480,549	480,549
11	Construction Work in Progress	3,313,663,483	3,308,678,099
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	36,813,443,180	36,776,542,740
14	Accum Prov for Depr, Amort, & Depl	14,996,520,980	14,987,309,946
15	Net Utility Plant (13 less 14)	21,816,922,200	21,789,232,794
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	14,564,638,485	14,555,427,451
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	431,882,495	431,882,495
22	Total In Service (18 thru 21)	14,996,520,980	14,987,309,946
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)	14,996,520,980	14,987,309,946

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

Gas (d)	Other (Specify) <i>WATER</i> (e)	Other (Specify) <i>COMMON</i> (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
4,101,394	26,694,473	1,119,189			3
					4
					5
					6
					7
4,101,394	26,694,473	1,119,189			8
					9
					10
533,034	3,893,427	558,923			11
					12
4,634,428	30,587,900	1,678,112			13
1,523,865	7,223,821	463,348			14
3,110,563	23,364,079	1,214,764			15
					16
					17
1,523,865	7,223,821	463,348			18
					19
					20
					21
1,523,865	7,223,821	463,348			22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,523,865	7,223,821	463,348			33

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	194,707,148	147,061,614
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	194,707,148	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	372,420	
9	In Reactor (120.3)	524,857,731	-191,335,091
10	SUBTOTAL (Total 8 & 9)	525,230,151	
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	414,543,349	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	305,393,950	
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 End of Year (f)	Line No.
Amortization (d)	Other Reductions (Explain in a footnote) (e)		
			1
			2
	119,567,211	222,201,551	3
			4
			5
		222,201,551	6
			7
	372,420		8
		333,522,640	9
		333,522,640	10
			11
			12
227,639,849		186,903,500	13
		368,820,691	14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

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

Transfer of costs from fuel in process to fuel in the reactor. Account 120.1)

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

Transfer of costs from fuel in stock to fuel in the reactor. Account 120.2)

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	2,847,931	
3	(302) Franchises and Consents	125,764,346	899,373
4	(303) Miscellaneous Intangible Plant	932,860,951	338,871,496
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,061,473,228	339,770,869
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,474,073	
9	(311) Structures and Improvements	57,686,769	2,535,248
10	(312) Boiler Plant Equipment	614,235,127	23,739,256
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	118,672,842	4,778,783
13	(315) Accessory Electric Equipment	45,891,234	1,592,438
14	(316) Misc. Power Plant Equipment	30,210,256	380,531
15	(317) Asset Retirement Costs for Steam Production	314,397	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	868,484,698	33,026,256
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,309,682	
19	(321) Structures and Improvements	1,607,475,397	30,173,741
20	(322) Reactor Plant Equipment	2,294,460,553	370,984,326
21	(323) Turbogenerator Units	847,410,092	18,553,133
22	(324) Accessory Electric Equipment	882,343,047	5,157,590
23	(325) Misc. Power Plant Equipment	550,436,533	897,513
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	6,184,435,304	425,766,303
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	5,076,047	2,056
28	(331) Structures and Improvements	113,635,279	12,409,696
29	(332) Reservoirs, Dams, and Waterways	442,149,229	11,095,099
30	(333) Water Wheels, Turbines, and Generators	125,219,207	4,829,729
31	(334) Accessory Electric Equipment	116,168,201	18,636,101
32	(335) Misc. Power PLant Equipment	11,254,614	111,053
33	(336) Roads, Railroads, and Bridges	10,246,966	223,271
34	(337) Asset Retirement Costs for Hydraulic Production	6,225,382	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	829,974,925	47,307,005
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,201,815	525,133
38	(341) Structures and Improvements	45,912,312	12,516,771
39	(342) Fuel Holders, Products, and Accessories	10,986,042	52,097
40	(343) Prime Movers	676,525,912	89,858,567
41	(344) Generators	84,878,856	282,208
42	(345) Accessory Electric Equipment	140,486,466	13,885,816
43	(346) Misc. Power Plant Equipment	3,954,803	393,174
44	(347) Asset Retirement Costs for Other Production	752,299	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	966,698,505	117,513,766
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	8,849,593,432	623,613,330

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	236,127,421	115,947
49	(352) Structures and Improvements	269,524,523	28,657,409
50	(353) Station Equipment	2,998,769,587	251,281,968
51	(354) Towers and Fixtures	648,130,598	27,114,663
52	(355) Poles and Fixtures	469,625,318	51,852,595
53	(356) Overhead Conductors and Devices	578,230,436	36,824,170
54	(357) Underground Conduit	40,230,419	2,537,250
55	(358) Underground Conductors and Devices	173,469,489	2,774,268
56	(359) Roads and Trails	30,991,609	921,046
57	(359.1) Asset Retirement Costs for Transmission Plant	2,314,846	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	5,447,414,246	402,079,316
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	101,019,128	703,536
61	(361) Structures and Improvements	388,978,987	16,807,762
62	(362) Station Equipment	1,363,544,934	101,941,014
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,386,109,994	158,694,991
65	(365) Overhead Conductors and Devices	983,227,538	72,980,834
66	(366) Underground Conduit	1,206,771,247	97,536,692
67	(367) Underground Conductors and Devices	3,487,893,544	302,045,895
68	(368) Line Transformers	2,476,361,896	255,388,116
69	(369) Services	1,051,459,026	39,338,594
70	(370) Meters	606,792,679	316,511,352
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	687,167,543	26,473,760
74	(374) Asset Retirement Costs for Distribution Plant	5,396,159	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	13,744,722,675	1,388,422,546
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	27,292,854	160,659
87	(390) Structures and Improvements	501,777,467	108,086,327
88	(391) Office Furniture and Equipment	554,073,716	107,582,056
89	(392) Transportation Equipment	7,762,381	7,686,753
90	(393) Stores Equipment	10,951,511	553,038
91	(394) Tools, Shop and Garage Equipment	41,498,202	13,836,634
92	(395) Laboratory Equipment	65,528,298	8,542,478
93	(396) Power Operated Equipment	3,405,961	44,621
94	(397) Communication Equipment	413,850,901	45,594,752
95	(398) Miscellaneous Equipment	13,595,364	2,838,940
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,639,736,655	294,926,258
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	454,810	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,640,191,465	294,926,258
100	TOTAL (Accounts 101 and 106)	30,743,395,046	3,048,812,319
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)	30,743,395,046	3,048,812,319

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
			2,847,931		2
	-1,444,723		125,218,996		3
85,545,181		963,278	1,187,150,544		4
85,545,181	-1,444,723	963,278	1,315,217,471		5
					6
					7
			1,474,073		8
693,083		-4,002,742	55,526,192		9
2,484,812		4,002,742	639,492,313		10
					11
2,794			123,448,831		12
83,580			47,400,092		13
10,506			30,580,281		14
	-10,715		303,682		15
3,274,775	-10,715		898,225,464		16
					17
			2,309,682		18
1,253,560		2,616,341	1,639,011,919		19
23,050,455		64,851,207	2,707,245,631		20
9,484,913		21,120,152	877,598,464		21
861,343		3,590,151	890,229,445		22
1,269,409		-92,177,851	457,886,786		23
					24
35,919,680			6,574,281,927		25
					26
	-12		5,078,091		27
203,636			125,841,339		28
437,766			452,806,562		29
152,489			129,896,447		30
484,721			134,319,581		31
			11,365,667		32
			10,470,237		33
	1,264,843		7,490,225		34
1,278,612	1,264,831		877,268,149		35
					36
			3,726,948		37
	-385,412	4,203	58,047,874		38
		-323,486	10,714,653		39
	-948,236	-79,029	765,357,214		40
			85,161,064		41
		391,424	154,763,706		42
		-43,798	4,304,179		43
	-752,299				44
	-2,085,947	-50,686	1,082,075,638		45
40,473,067	-831,831	-50,686	9,431,851,178		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				47
	-349,855		235,893,513	48
272,200			297,909,732	49
35,314,964			3,214,736,591	50
5,196			675,240,065	51
3,505,243		-18,768	517,953,902	52
201,188			614,853,418	53
			42,767,669	54
282,167			175,961,590	55
			31,912,655	56
	1,792,275		4,107,121	57
39,580,958	1,442,420	-18,768	5,811,336,256	58
				59
	-19,628		101,703,036	60
6,375,349			399,411,400	61
8,430,001			1,457,055,947	62
				63
6,351,633		20,271	1,538,473,623	64
6,518,680		246	1,049,689,938	65
3,443,834		205,272	1,301,069,377	66
25,263,951		4,201	3,764,679,689	67
30,448,599			2,701,301,413	68
1,407,040		-209,450	1,089,181,130	69
165,653,056			757,650,975	70
				71
				72
5,216,396		-268	708,424,639	73
	3,543,856		8,940,015	74
259,108,539	3,524,228	20,272	14,877,581,182	75
				76
				77
				78
				79
				80
				81
				82
				83
				84
				85
	-600		27,452,913	86
5,258,925			604,604,869	87
74,476,232		-963,278	586,216,262	88
3,434,508			12,014,626	89
1,036,048			10,468,501	90
3,312,451		50,686	52,073,071	91
2,697,785			71,372,991	92
3,404,451			46,131	93
34,742,714		-1,504	424,701,435	94
1,477,191			14,957,113	95
129,840,305	-600	-914,096	1,803,907,912	96
				97
	298,198		753,008	98
129,840,305	297,598	-914,096	1,804,660,920	99
554,548,050	2,987,692		33,240,647,007	100
				101
				102
				103
554,548,050	2,987,692		33,240,647,007	104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	350 - Land and Land Rights:			
3				
4				
5	Under \$250,000 (4 Properties)	Various	Various	210,090
6				
7				
8				
9	360 - Land and Land Rights:			
10				
11				
12	Under \$250,000 (2 Properties)	Various	Various	270,459
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			480,549

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	***** WORK ORDERS OVER \$1,000,000 *****	
2		
3	Rector Sub - Install Water Line	1,003,912
4	BEAR MTN C.S.- Install Microwave Tower, Antennas	1,004,098
5	ALDER-DECLEZ 66KV: Install Cable and Underground Facilities	1,005,020
6	Goleta: Install four new 220 kV banks	1,005,479
7	CO Rivera Rd. Bridge - Replace poles and overhead facilities	1,011,948
8	Purchase existing overhead distribution facilities	1,014,592
9	PVCB - Outage Support Facility	1,019,570
10	Relocate Facilities	1,021,941
11	PVCB - Power Expansion Plant West	1,028,337
12	Valley Sub - Equip a new 115kV Transformer	1,035,273
13	Casitas - Replace #1 and #2 66/16kV Bank	1,039,135
14	WRF - Evap Pond #1 Liner Replacement	1,042,549
15	Big Creek #3 - Install a Second Transformer	1,047,653
16	Monrovia Service Center - DSP Circuits Program	1,051,472
17	Non-Unix Operating Software	1,061,029
18	ADC Network Infrastructure	1,064,508
19	Install Data Network System	1,064,621
20	Hamilton - Replace #1 and #2 66/12k Transformer Bank	1,067,367
21	ANTELOPE SUB - Install Antenna Support Structures and Assemblies	1,073,798
22	Rule 20A UG - Install Underground Facilities	1,075,859
23	PCH Hwy/Carbon Cyn, Install Underground Facilities	1,077,115
24	Valley - Highgrove - Install FO Cable	1,078,096
25	Mohave - Replace 2 500kV banks	1,079,709
26	Relocate Facilities	1,083,992
27	Big Creek #4 - Relicensing	1,086,505
28	Install LW, MW, Chann, Communication Equipment	1,087,613
29	WRF - TF Rehabilitation	1,088,690
30	CMDB Project Phase II	1,089,026
31	Factory Acceptance Testing facility	1,089,670
32	TippingPoint Upgrade- MWO	1,094,375
33	Kern River #3 - Replace Wicket Gate	1,095,971
34	Stanhill Sub - Install a New Transformer Bank	1,098,148
35	Install Underground Facilities	1,100,586
36	Claremont Sub: Replace Existing 11.2mva Transformer With New22.4mva Transformer	1,105,715
37	PBGS-Install Control Room Equipment	1,107,424
38	Niguel Sub - Add a 66KV Capacitor Bank	1,110,434
39	Saugus-Haskell-Solemint & Saugus-Lockheed And Antelope-P.S. 74 66kv Lines	1,111,956
40	Horsetown Sub - Construct a New Substation	1,114,502
41	ESC Data Warehouse Project Management	1,116,497
42	Pond Liner Replacement	1,116,655
43	TOTAL	3,308,678,099

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	CO Convert Overhead to Underground Facilities	1,117,678
2	CO Remove Idle 115kv Facilities	1,119,916
3	Acquire TRTP Segment 2 Properties	1,122,482
4	Rancho Facility Capital Improvements	1,126,285
5	Watson - Replace #1, #2, and #3 66/12kV Transformers	1,128,569
6	PBGS - Install D.C. Supply System	1,133,891
7	ITKO! LISA Virtualize (VTE) Hardware	1,139,515
8	Kern River - Replace #1 BANK & 66KV CB'S	1,141,674
9	AMELIA - Replace Failed 16KV Switchrack	1,142,681
10	Added Facilities	1,153,017
11	Devers Sub - Install Dissolved Gas Analysis Units and Communication Equipment	1,153,616
12	Hinson Sub - Replace Four Circuit Breakers	1,156,393
13	Yucaipa Valley Brineline Extension	1,157,374
14	Ontario Annex - Capital Improvements	1,164,933
15	SONGS Unit 2 - Inverter Modifications	1,166,069
16	SONGS U2 & U3 - Upgrade Technical Specifications	1,171,375
17	Ontario Service Center - DSP Circuits Program	1,175,272
18	Moorpark East CCR Malibu - Install Fiber Optic Cable	1,177,078
19	Santa Ana # 3 Replace Office "Yellow Phone" System	1,183,139
20	CO System Project - Relocate Facilities	1,192,096
21	Olinda-Atwood-Brea-Carolina 66kv: Convert O.H. To U.G. Rule 20/C	1,197,901
22	U2 Rapid Refueling Quicklocs Material	1,199,005
23	Gateway Parking Structure - Capital Improvements	1,204,379
24	Montebello District Office - DSP Circuits Program	1,205,405
25	Covina Service Center - Install a New Truck Bay/Hoist	1,209,687
26	Rule 20A Install Underground Facilities	1,215,670
27	Install New Cyber Security System	1,219,444
28	TRTP 1 - Environmental Mitigation	1,227,712
29	GIS Hardware: Developing Environment	1,232,983
30	Santiago Sub - Install Transformer Banks and Station Equipment	1,240,793
31	Lessandro-Highgrove-Maxwell-Tanker 115kv - R/R 2-1/2 Mi (75 Wood Poles)	1,245,493
32	SYLMAR/LADWP - Sylmar Replace Overhead Conductor	1,248,694
33	TRTP Segment 7 - Acquire Land	1,261,606
34	Install Rule 20B Structures	1,284,364
35	Ventura SC - Install Underground Facilities	1,289,217
36	VMWare Pre-Staging Servers - GO2	1,292,504
37	SONGS ISFSI Canister 46	1,295,791
38	SONGS ISFSI Canister 47	1,298,922
39	SONGS ISFSI Canister 45	1,299,381
40	SONGS ISFSI Canister 44	1,301,803
41	SONGS - New Cyber Security Design	1,309,981
42	Leased Facilities Improvements	1,310,248
43	TOTAL	3,308,678,099

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	Southbay Service Center - Replace Underground Facilities	1,313,326
2	Rule 20A - Install Underground Facilities	1,313,398
3	Palm Springs SC - Facility Improvements	1,313,791
4	SONGS - Fire Protection	1,317,527
5	Bark Beetle Project Replacement/Repairs	1,322,211
6	Relocate Poles/Street Improvement	1,330,180
7	Rancho Vista (Reliant Generating Plant) Relocate Well Easement	1,330,345
8	Mohave Generating Station Facilities	1,331,015
9	Niguel Sub: Replace No.4 Transformer	1,340,305
10	LC: Hardware Purchase/Set-up	1,340,412
11	Etiwanda - Declez No. 1 66kV - Replace Cable	1,346,917
12	Replace U2&3 CCW Heat Exchangers	1,354,063
13	TRTP Segment 9: Mesa Sub: Equip Position	1,368,995
14	El Casco-Mentone - Install FO Cable	1,375,791
15	Kanan - Install Underground Facilities	1,376,511
16	San Gorgonio - Relicensing	1,381,683
17	Vincent-Monrovia - Replace Communication Equipment	1,381,642
18	Irvine Operations Center ADC: PoC Adv Virtu Tech (H/W) - ITC	1,387,095
19	Install Rule 20A Structures	1,394,915
20	Install Antenna, Lightwave, Radio, Channel, Alarm Control, DC Power, Data Network	1,396,421
21	Ship: Construct a new 56MVA, 66/12k Sub	1,397,134
22	UIPlanner Project - MasterWO	1,403,618
23	Medical Sub - Added Facilities	1,407,107
24	Corona Sub - Construct a New 33kV Switchrack	1,407,836
25	Kern River No.1 - Install a Powerhouse Access Road	1,408,064
26	CO Install Underground Facilities	1,429,536
27	TRTP Segments 5-2: Antelope-Vincent-Windham	1,433,009
28	RTP Segment 8-Chino-Walnut F.W. 0204	1,437,025
29	Kern River No.3 Unit 2 Rewind Stator	1,458,768
30	CO Install new 66kv conductor. 4305	1,464,220
31	Downey Med (Kaiser): Construct New 66/12kv Sub	1,467,647
32	SPVP Capital-Not Site Specific	1,476,031
33	Downs Sub: Install New 6 Position	1,477,471
34	SONGS Unit 2 RRF Materials - Temperature Monitor	1,479,053
35	Menifee SC - Install Line Extension	1,482,920
36	Bishop Hydro - Housing Upgrades - Plant 4	1,482,961
37	Commodity Management Platform Program	1,486,348
38	Microsoft Upgrade Program - Windows	1,489,253
39	SONGS Unit 2 - Rapid Refueling	1,490,169
40	Install Data Network	1,495,423
41	S/A Santiago-Borrego-Morro & Santiago-Borrego 66kv T/L	1,497,463
42	Santa Rosa Sub - Emergency Spare Transformer	1,503,137
43	TOTAL	3,308,678,099

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	Big Creek No. 1 - Camp Cottage Renovations	1,503,272
2	Songs Unit 2 - Nsr Chiller Control	1,513,667
3	Conversion of PF Overhead to Underground	1,517,504
4	Install Approximately 2500 of 1750 KCMIL Cable	1,527,332
5	PPM Enterprise Foundation - Master	1,529,798
6	Palo Verde Common - Capital Improvements	1,550,776
7	Install a New 66kv Switching Station For Lancaster LACSD	1,558,471
8	CO System Project: W.O.4048	1,569,986
9	VI System Project	1,571,273
10	Moorpark - Newbury No. 2 - Install Fiber Optic Cable	1,572,655
11	ESC SOC Facility	1,580,218
12	Non-Exempt (Portable) Tools and Work Equipment	1,581,364
13	Kern River No. 1 - Replace 66kV Circuit Breakers	1,582,384
14	Generation Automation Installation	1,584,312
15	Tap to New Substation District For LACSD	1,585,256
16	Operations Application Tools	1,601,454
17	ERP Scheduling P2	1,602,198
18	Enterprise Streaming Video Services	1,604,255
19	Kern River - Borel Forebay Renovations	1,606,634
20	Engineer and Construct A New 115 / 12kv Customer Substation	1,606,933
21	Rule 20A - Install Underground Facilities	1,622,498
22	SONGS ISFSI Canister 48	1,628,095
23	Construct A New Substation with MVA Transformers	1,631,286
24	CO Install 66kv Underground Facilities	1,633,374
25	Control Station Automation Updgrade	1,633,661
26	2010 SAP Usability	1,646,038
27	Kramer-Lugo #1 & #2: Relocate Transmission Lines	1,650,553
28	Palo Verde Common - Nuclear Admin & Tech Manual	1,660,023
29	Business Objects - EIM Project	1,660,691
30	Install Underground Facilities	1,665,491
31	EL DORADO Sub - Install a Permanent Water Line	1,668,314
32	Big Creek 2 - Install a 12kv Substaion	1,669,678
33	Antelope Valley Sc - DSP Circuits Program	1,672,969
34	Engineer and Construct A 16.8 MVA 115/4kv Customer Dedicated Substation	1,675,223
35	Cathedral City Sub - Replace No.1 & No. Transformer Banks	1,695,428
36	Etiwanda - Declez - Install Underground Facilities	1,697,105
37	North Orange County - DSP Circuits Program	1,699,223
38	Poole - Replace Station Lighting	1,703,192
39	SONGS U2 - Replace Batteries	1,703,231
40	MSO Meter Shop Equipment	1,711,616
41	Morongo Relocation: Preliminary Engineering	1,732,431
42	Redlands Service Center - DSP Circuits Program	1,749,869
43	TOTAL	3,308,678,099

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	Grand Crossing - Construct New Substation	1,749,972
2	Menifee Service Center - DSP Circuits Program	1,762,731
3	PV2PM - UFM System Replacement, U2R	1,775,604
4	ERP Firewall & ESS	1,776,084
5	U3 RRVH Installation - Westinghouse	1,786,815
6	CO Convert Overhead to Underground Facilities	1,787,774
7	Central OC District - Install Underground Facilities	1,793,113
8	Eisenhower: Installation of SAS	1,793,855
9	Wildlife (Formerly Jurupa): Install New 220kv Switchyard Facilities	1,795,196
10	CMS Capital Master Work Order	1,802,741
11	Garnet - Santa Rosa 115kv - Replace Overhead Facilities	1,821,662
12	Tehachapi S/C Renovation - Capital Improvements	1,823,667
13	Install Data Networking Equipment	1,845,612
14	On Boarding	1,855,510
15	Rule 20B Install Structures/Cable	1,865,250
16	Mayberry Sub - Install Station Equipment	1,878,768
17	SONGS ISFSI Canister 43	1,880,880
18	Tamarisk: Replace No.1 N & 1 S Transformers	1,881,157
19	Leatherneck Sub - Phase 1, Added Facilities	1,898,967
20	Newmark: Replace the 2N & 2S Transformers	1,906,916
21	Consolidated Mobile Solution (CMS)	1,908,657
22	SONGS U2 Instrument Air Mods	1,920,367
23	Install MVA Banks, Rack with Circuit Breakers	1,921,525
24	Rule 20B - Install Underground Facilities	1,921,767
25	ECMP Project Blade Server - GO2	1,926,709
26	Install Fiber Optic Cables	1,927,433
27	Oak Park C.S. - Replace Microwave and Communication Equipment	1,936,515
28	Highwind: Grade And Fence New Highwind 230 Kv Substation	1,957,197
29	Santa Rosa: Replace No. 6 N & 6 S Transformers	1,968,155
30	Infrastructure Replacement Program	1,971,736
31	Huntington Lake Dam Nos. 1 & 2 - Replace Controls	1,982,759
32	Devore Sub - Construct New Substation	2,014,992
33	Padua: Replace relays: CO-8, CO-5,	2,044,272
34	VI Relocate ISO Rack Span	2,048,528
35	Acquire R/W Easement	2,072,386
36	Install New 20MVA 66/12kv Customer Dedicated Tapped Substation	2,088,043
37	A6 - Regulatory Compliance Monitor	2,092,788
38	Weymouth Sub - Install a New Substation	2,093,205
39	Install Data Networking Equipment For Rivergrade Complex	2,102,917
40	SONGS U2 Replace EDG Equipment	2,114,630
41	Srun - 2010 DCMS Enhancement	2,117,336
42	Transmission Line Separation Project - Federal Lands	2,155,424
43	TOTAL	3,308,678,099

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	SG POC: Pur. and Inst. H/W	2,160,688
2	Bayside 66KV: Convert Overhead to Underground Facilities	2,161,371
3	Sylmar/LADWP Celilo-Sylmar DC Transmission Line Tower Replacement	2,166,588
4	Antelope Valley SC - DSP Circuits Program	2,172,180
5	San Bernardino-Vista - Transmission Line Upgrade	2,206,060
6	Unix OS 2010 - Master Order	2,210,360
7	Songs Unit 3 - Salt Water Cooling Pumps	2,226,674
8	Pebbly Beach GS- Install New 1.2MW SOD SELF	2,253,805
9	SONGS U3 Inverter Y005 & Charger	2,258,229
10	Songs Unit 3 - 1E 480v Load Center Transformers	2,282,346
11	Center - Install Redundant Fuel Gas Compressor	2,287,620
12	SONGS TPCW Unit 3	2,290,423
13	Thrive Sub: Engineer and Construct New Substation	2,310,222
14	Install On-Line Dissolved Gas Analysts Units	2,310,367
15	Four Corners G.S. - Partial Econo and Reheat Exchanger	2,319,440
16	Install Channel, Lightwave, Microwave, Antennas, Tower	2,323,136
17	66kv Rio Hondo-Arcadia Rule 20A From Monrovia Boundry To Arcadia Bound	2,327,968
18	Lakeview Sub: Licensing	2,329,870
19	2009 Unix Storage - IOC	2,335,902
20	Barre Sub - Fuel Gas Compressor	2,337,668
21	Pisgah Sub (Phase 1 - Up to 275 MW.	2,338,783
22	Erp Gdt - Capital Software	2,348,031
23	Distribution Management System (DMS) Hardware	2,355,396
24	Installation of Underground Per Rule 20B	2,364,898
25	Server Sub: Construct a new 56 MVA Substation	2,372,468
26	TDBU Comprehensive Pilot GIS	2,375,421
27	Acton Sub: Construct 66kV Switchrack	2,382,485
28	SONGS U3 - Replace Non 1E Batteries	2,399,606
29	UNIX Pre-Staging Servers - IOC	2,428,100
30	ESC DW Hardware - Rosemead	2,430,389
31	Montebello District Office - DSP Circuits Program	2,430,534
32	CCO Capital Master Work Order	2,440,873
33	Ontario Land Purch-Laydown Area	2,441,634
34	SONGS U3 Rapid Refueling Modifications	2,458,145
35	Devers - San Bernardino T/L - Loop the Existing Line to El Casco Substation	2,458,600
36	El Segundo: Engineering, Design, Construction, Grid Functional Facilities & Equipment	2,461,095
37	SONGS - SAP Conversion Order	2,474,448
38	SONGS- XP Implementation	2,480,381
39	Little Rock Substation - Replace Station Equipment	2,499,790
40	SONGS U3 FFCPD Replacement Cap	2,500,595
41	Gen Tie-Line: Install the line drop	2,503,328
42	Install Necessary Protective Relays	2,511,208
43	TOTAL	3,308,678,099

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	Reduction Sub: Expand existing 66kV	2,517,371
2	SONGS - Life Cycle Management Program	2,543,604
3	ESC - IT Monitoring Tool Systems IO	2,549,700
4	Tipton Sub: Replace Bank 1 & 2	2,570,103
5	Moorpark-Newbury 66kV - Reconductor Line	2,580,652
6	Hardware	2,619,368
7	Foothill SC - DSP Circuits Program	2,622,866
8	SONGS - Repave Roads	2,629,670
9	TRTP Segments 11-2: Mesa-Gould 220kV - Structures	2,640,762
10	Microsoft Upgrade Program - Office	2,647,497
11	Modify Main Building and Replace Garage	2,647,893
12	TRTP Segment 7-2: Vincent-Rio Hondo #2 - Construct T/L	2,648,324
13	Sun City - Install 1-28 MVA Transformers, Station Equipment	2,652,736
14	Kramer: Replace (11) 115kV Circuit Breakers	2,656,327
15	Rector Sub: Replace Existing 2A Transformer Bank	2,697,779
16	ECMP Project Blade Server - IOC	2,715,165
17	Bottle Sub: Install A New 16.8mva 115/4kv Customer Dedicated Substation	2,728,480
18	IdM Enhancement -- 2010 - Master WO	2,749,681
19	Enterprise Technology Service - Phase 3	2,755,076
20	Mira Loma Peaker - Install OPR/Maint	2,777,495
21	Garnet-Santa Rosa 115kV - Underground Cable Replacement	2,794,426
22	ESC - IT Monitoring Tool - Systems	2,798,611
23	EPP Phase 2 project start request	2,805,913
24	TRTP Segments 4-3: Path 26 Loop: Construct Transmission Line	2,807,926
25	ESC Master Interim HAN Dev Reg P1	2,842,900
26	PPM for EPM Project	2,864,596
27	SONGS U3 Capital Replacement Superior	2,873,003
28	AMI System Integrator DCA Development Software	2,887,952
29	AMI System Integrator System Architecture Software	2,889,644
30	Palo Verde Switchrack - Capital Expenditure For Plant	2,889,649
31	Enhance Perimeter Defense	2,941,582
32	TRTP Segments 4-11: Licensing	2,959,425
33	TRTP Segments 6-4: New Vincent-ANF 500kV T/L	2,973,321
34	EDI Upgrade -Master Wo	2,990,240
35	TPM Software Enhancement	2,990,728
36	Sc Jh R/R Towers W/66-Tsp's, Seg.4	2,992,316
37	Devers-Palo Verde 500kV: Reinforce Legs On Various Towers	3,004,119
38	Srun - 2010 DCMS New	3,008,625
39	TRTP Segment 5 - Land Acquisition	3,009,423
40	Northern T/S - Land Acquisition	3,027,712
41	Install New 56MVA 115/12kv Customer Dedicated Substation	3,038,816
42	Rector 230kV Switchrack: Install	3,054,199
43	TOTAL	3,308,678,099

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	iRise Visualization Tools - Master	3,058,132
2	Antelope Valley SC - Replace Overhead Conductor	3,104,127
3	Center: Install Integrated Video Surveillance	3,140,447
4	Install PHSC Line for Songs Unit 2	3,147,666
5	Rule 20B - Install Underground Facilities	3,182,530
6	Mobile Device Encryption	3,184,825
7	Songs Unit 2 - Tpcw Heat Exchanger	3,231,939
8	Bunker Sub - Add 1-28 MVA Transformer and Equip Circuit Position	3,250,553
9	PVCPM - Plant Aging Management Project	3,283,689
10	TRTP Segment 3C-3: Vincent 500kV - Equip Line Position	3,317,080
11	SONGS U3 - New DCS Boration Dilution	3,364,356
12	Vincent: Replace 1AA Transformer	3,370,983
13	Mira Loma - Install Redundant Gas Compressor	3,389,673
14	ISO Market Enhancements Program	3,394,395
15	TRTP Segment 9: Gould Sub : Add Circuit Breakers	3,409,033
16	Menifee SC BLDG 3 Remodel Phase 3 C	3,412,693
17	TRTP Segment 9: Windhub Substation- Station Upgrade	3,416,028
18	Orcosan Sub: Engineer & Construct A 44.8mva, 66/12kv Customer Dedicated Substation	3,420,648
19	South Bay - Install Underground Facilities	3,431,497
20	Grapeland - Install Redundant Gas Compressor	3,479,370
21	Install Structure/Cble Per R20b(Hill Central)	3,500,050
22	ESC Data Warehouse Architecture & Design	3,520,588
23	MRTU-Capital Master WO MS/PM/MS/ARC	3,565,012
24	PKI Capital Master Work Order	3,638,318
25	Shaver Lake Dam - Geomembrane Liner	3,667,877
26	Randsburg: Replace #1 Transformer Bank	3,673,104
27	Romo - Install Communications Equipment	3,731,923
28	Redlands #2 2290 Palmetto Ave - Service Center	3,820,370
29	Big Creek No. 8 - Replace Main Transformer #1	3,827,315
30	SONGS Actionway Software Upgrade	3,856,258
31	SONGS WNU-00128 AHSMs 48-63	3,936,821
32	Victor-Savage - Reconductor 115kV Line	3,971,220
33	2009 Unix Storage GO	3,990,565
34	PVCPM - Security Access Control System	4,001,914
35	Phsr Measuremnt & Grid Stability	4,007,677
36	Superior Work order for Web present	4,065,783
37	TRTP Segment 9 - Land Acquisition	4,095,262
38	Purchase 2 each 2 Mega Watt Batter	4,096,535
39	DMX Project 2008 / Sevag	4,118,068
40	Diemer Sub - Install a New Substation	4,140,570
41	Victor - Reconstruct 115KV Switchrack	4,172,651
42	CO Relocate Transmission Line	4,190,085
43	TOTAL	3,308,678,099

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	Catalina Service Center	4,197,632
2	Construct New 115/12kv Substation	4,223,335
3	Engineer And Construct New 56 MVA Substation	4,394,205
4	Install New 28 MVA Bank	4,508,415
5	Customer Service (Csbu) - Ami Phase 3 - Facility Capital	4,545,063
6	Additions / Retirement Portable Tools and Work Equipment	4,552,863
7	San Bernardino - Added Facilities	4,638,686
8	Remove 115/12kv Transformer And 12kv Voltage Regulator	4,685,135
9	NERC CIP Capital Master Order	4,750,981
10	Bliss Sub - Replace Bank 1 and Bank 2	4,770,722
11	ERP CRM Tech HW - CRM Core (IOC)	4,789,751
12	PVCER - Component Design Basis	4,820,528
13	Integrated Postal Compliance R2 Program	4,830,246
14	Replace Intake Structure And Equipment	4,853,810
15	Alhambra Data Center (GITC) - Capital Improvements	4,899,714
16	Victor-Rivertex: Install Approx. 8.1 Miles Of New Single Ckt115kv Line	4,947,730
17	Triton Sub: Construct new 115/12kv Substation	4,957,344
18	C 08 MPR Replace HB Valve	4,987,094
19	Kern River No. 3 - Replace Automation	5,014,986
20	Ellis Sub: Phase I: Install No.3	5,104,000
21	Pastoria Sub - Construct Interconnection	5,164,315
22	Build a New 41.6 Miles Single-Circuit 500K Transmission Line	5,457,999
23	Construct New 500kv Substation	5,529,638
24	TRTP Segment 8-2 - Construct Transmission Line	5,535,056
25	ESC DW Hardware - Irvine	5,585,889
26	CRM CAPITAL-Blue Print	5,592,994
27	AMI Systems Integrator - MDMS Development Software	5,630,735
28	Reconfigure 115kv Switchyard & Add 33kv Circuits to Increase Capacity	5,688,881
29	Install The 3rd 220/115kv Transformer Bank No 3A	5,744,026
30	Replace Existing 66kv 1200A CB of Transformer Bank No. 2A	5,774,678
31	Unix Servers - IOC	5,786,238
32	Songs Unit 3 - High Pressure Turbine U3 Replacement	5,849,985
33	San Bernardino Sub - Upgrade Existing Equipment	5,854,168
34	Valley: Interconnect 669 Mw Of Generation To The Valley 500kv Bus	5,898,610
35	North Coast Office Building Purchase	5,898,930
36	Ivyglen: Bring In Second 115kv Line From Valley To Ivyglen	6,021,070
37	Big Creek No. 3 - West Gate, Bushings & L Platform	6,069,474
38	Dock Sub - Construct a New Substation	6,087,832
39	Construct A New Operations And Maintenance Building	6,088,851
40	ERP SW Rollout 3	6,098,533
41	DISTRIBUTION MGMT SYSTEM (DMS)	6,236,152
42	Microsoft ELA - Windows Desktop Upgrade	6,322,315
43	TOTAL	3,308,678,099

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	Santiago Sub - Install Seven 230kV Circuit Breakers	6,323,467
2	ESC R3 Superior Software Work Order	6,354,456
3	Data Center Program-Master WO	6,589,855
4	PLKaiser DC #6 9415 Kaiser Way Fontana	6,625,632
5	2010 Mainframe Storage - IOC	6,804,979
6	Monrovia SC - Install Underground Facilities	6,977,815
7	Pebble Beach - Install 25 New Micro Turbines	7,139,319
8	TRTP Segment 8-7: CHINO-MIRA LOMA #1 & #2 - Construct Transmission Line	7,175,240
9	PLKaiser DC #2 13277 San Bernardino	7,252,011
10	Install 115kv 28MVA LTC Transformer	7,284,225
11	Construct 15 Miles of 954 SAC to Form New CO To Banning	7,528,978
12	Domino 8/Lotus Notes - Master Work	7,564,667
13	Songs Unit 3 - Hydraulic Governor Digital Control	7,574,023
14	Devers-Mirage 115kv System: Split The Devers-Mirage 'A' System Into Separate Lines	7,623,619
15	Mohave - 'C' Aquifer Study, To Perform Preliminary Engineerin, Environment Assessment	7,745,304
16	CSBU -AMI SmartConnect It Software Development	7,912,670
17	Songs Unit 2 - Digital Speed Control Upgrade	7,917,295
18	TRTP Segment 9: Mira Loma Substation	8,014,986
19	TRTP Segment 10 - Land Acquisition	8,113,872
20	Alhambra Grid Operations Upgrade	8,566,586
21	Seaggett Sub - Engineer and Construct New Substation	8,668,781
22	DPV2-AZ Post September 2005	8,804,931
23	SONGS U3 Instrument Air Project	9,015,773
24	CEH&S Compliance Mgmt System - Phase 3	9,293,984
25	Preliminary Engineering Rector Substation with New 15 Mile Double CKT	9,395,889
26	C 08 Mid Canyon Machine Shop	9,702,051
27	Enterprise Content Management	10,002,259
28	FERC - Tehachapi Renewable Transmission Segment 8	10,189,001
29	Chino Air Ops-New Hangar -CAPITAL	10,233,717
30	MS Office-Office 2007/License Agree	10,360,777
31	WRF - Evap Pond #2 Liner Replacement	10,503,301
32	Ivanpah Sub: Initial Land Studies And Environmental Analysis.	10,519,565
33	Install 7 Miles of 230kv Lines	10,539,961
34	DCR: Colorado River - Devers #2	10,897,583
35	FERC - Antelope Transmission Segment 4	11,130,912
36	Kern River No. 1 Tunnel Rebuild Phase 4	11,353,513
37	Rio Hondo: Equip The 230kv A-Banks	11,428,044
38	Mohave Continued Operation Project - Phase 1 Preliminary Engineering	11,608,106
39	ESC Data Warehouse Superior Work Order	11,939,686
40	PE & Environmental Work	12,101,514
41	Songs Unit 2 - High Pressure Turbine Replacement	12,149,015
42	SONGS - Security Rule Implement	12,771,754
43	TOTAL	3,308,678,099

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	PL9687 Trans Way TIE1 Fontana	13,531,994
2	Mesa-Vincent #1 500kV: Construct Transmission Line	13,570,292
3	Whirlwind-Windhub 500kv: Construct Transmission Line	13,706,822
4	Santa Clara Sub - Install Transformers and Station Equipment	13,978,654
5	GO2 Data Center Upgrade to Mechanical And Electrical Systems	14,754,472
6	Valley Sub - Add a Transformer Bank	15,264,147
7	Alberhill Sub - Land Acquisition	15,624,634
8	ESC R1 MDMS Capital Master SW WO	16,033,259
9	New Vincent-Duarte 500kv: Construct Transmission Line	17,089,987
10	Ferc - Antelope Transmission Project Phase 1 Segment 3	17,103,963
11	CRM Project Master Work Order	18,120,754
12	Windhub-Highwind 230kv T/L: Construct New 9.6 Miles Transmission Line	18,718,272
13	Antelope-Mesa 230kv T/L: Construct Transmission Line	19,030,979
14	TRTP 9: Antelope Sub - Upgrade 500kV Position	21,565,978
15	Antelope-Whirlwind 500kv T/L: Construct Transmission Line	23,234,397
16	Pomona - Innovation Villarge 3 - Construct Facility	23,702,729
17	Julian Hinds Sub - Install New Line Position	23,742,169
18	Antelope-Vincent #2 500kV - Construct Transmission Line	23,752,673
19	Palo Verde: Preliminary Engineering And Environmental Work	25,344,002
20	GO #5 Building Remodel - Capital Improvements	29,224,827
21	TRTP Segment 9: Whirlwind - Construct New Transmission Line	32,612,447
22	Songs Unit 2 - Replace Rpv Heads	33,122,966
23	Install New Three Phase 280 MVA 220/115kv Transformer Bank No 3A	33,229,163
24	Songs Unit 3 - Replace Rpv Heads	33,298,697
25	TRTP Segment 9: Vincent Substation - Upgrade Substation	35,012,137
26	Antelope-Vincent #2 500kV Transmission Lines	45,544,378
27	Purchase And Install Natural Gas Fired Combustion Turbine	52,654,641
28	El Casco Sub - Construct New Switchrack	58,090,428
29	Mira Loma-Vincent: Construct New Transmission Line	59,916,603
30	TRTP Segment 3C-5: Antelope Substation	66,965,179
31	TRTP Segment 3C-1: Windhub 500kV Upgrade	76,627,056
32	Unit 3 SGRP Master Order	284,141,435
33		
34	***** WORK ORDERS UNDER \$1,000,000 *****	849,274,852
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	3,308,678,099

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	14,162,546,610	14,162,546,610		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,055,452,850	1,055,452,850		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,639,261	1,639,261		
7	Other Clearing Accounts	3,926,602	3,926,602		
8	Other Accounts (Specify, details in footnote):	67,961,211	67,961,211		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,128,979,924	1,128,979,924		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	469,002,868	469,002,868		
13	Cost of Removal	305,320,004	305,320,004		
14	Salvage (Credit)	35,827,147	35,827,147		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	738,495,725	738,495,725		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	Other Items	2,396,642	2,396,642		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	14,555,427,451	14,555,427,451		

Section B. Balances at End of Year According to Functional Classification

20	Steam Production	816,334,793	816,334,793		
21	Nuclear Production	5,729,255,295	5,729,255,295		
22	Hydraulic Production-Conventional	346,657,871	346,657,871		
23	Hydraulic Production-Pumped Storage				
24	Other Production	165,999,746	165,999,746		
25	Transmission	1,646,552,360	1,646,552,360		
26	Distribution	5,117,953,970	5,117,953,970		
27	Regional Transmission and Market Operation				
28	General	732,673,416	732,673,416		
29	TOTAL (Enter Total of lines 20 thru 28)	14,555,427,451	14,555,427,451		

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	Energy Services Inc.			
2	Capital Stock	12/06/68	none	10
3	Additional Paid-in Capital	12/06/68	none	99,990
4	Undistributed Earnings			7,488,785
5	Subtotal			7,588,785
6				
7	Mono Power Company			
8	Capital Stock	03/02/70	none	100
9	Additional Paid-in Capital	03/02/70	none	2,749,150
10	Undistributed Earnings			-2,068,850
11	Subtotal			680,400
12				
13	Southern States Realty			
14	Capital Stock	01/22/73	none	100
15	Additional Paid-in Capital	01/22/73	none	
16	Undistributed Earnings			73,995
17	Subtotal			74,095
18				
19	SCE Capital Company			
20	Capital Stock	09/10/82	none	20,000
21	Additional Paid-in Capital	09/10/82	none	100,000
22	Undistributed Earnings			-2,727,886
23	Subtotal			-2,607,886
24				
25				
26				
27				
28				
29	Subtotal			
30				
31				
32				
33				
34				
35	Subtotal			
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	2,969,350	TOTAL	5,735,394

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4		-	-	
5	Subtotal			
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
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27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 \$	2,969,350	TOTAL	5,735,394

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 from investments, including such revenues from 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
		10		2
		99,990		3
750,106		8,238,891		4
750,106		8,338,891		5
				6
				7
		100		8
		2,749,150		9
-2,937		-2,071,788		10
-2,937		677,462		11
				12
				13
		100		14
				15
-97,782		-23,786		16
-97,782		-23,686		17
				18
				19
		20,000		20
		100,000		21
-1,840		-2,729,725		22
-1,840		-2,609,725		23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
647,547		6,382,942		42

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 from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
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				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
647,547		6,382,942		42

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)	26,716,937	21,084,268	Various
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)	239,773,036	258,153,728	Various
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	36,937,089	34,302,500	Various
8	Transmission Plant (Estimated)	2,147,995	2,841,307	Various
9	Distribution Plant (Estimated)	11,114,463	12,205,473	Various
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	3,892,673	3,478,114	Various
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	293,865,256	310,981,122	
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)			Various
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	320,582,193	332,065,390	

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 227 Line No.: 11 Column: d
Other Business groups such as office buildings and general office supplies.

Name of Respondent
Southern California Edison Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/18/2011

Year/Period of Report
End of 2010/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	NONE					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
21	SONGS #2 - Amount to be amortized	15,702,337		407	-110,767	1,283,053
22	over a 25 year period beginning					
23	January 1989 to December 2013					
24						
25	SONGS #3 - Amount to be amortized	15,296,204		407	-108,088	1,252,025
26	over a 25 year period beginning					
27	January 1989 to December 2013					
28						
29	Palo Verde Nuclear Generating	7,772,588		407	-53,237	802,993
30	Regulatory Study Cost					
31						
32	Unamortized SONGS #1 Plant	636,913,184				
33	Investment					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	675,684,313			-272,092	3,338,071

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	Interconnection Studies	11,783	143	285,654	143
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	Generation Studies				
22	Interconnection Studies	6,951,195	143	(5,843,587)	143
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 231 Line No.: 2 Column: a

Transmission Interconnection Studies include interconnection studies related to transmission interconnection requests and wholesale load interconnection requests.

Project Type	Description	Description	Account Charged	Reimbursements received During Period	Account Charged with Reimbursements
Transmission	800063833 Interconnection Study	\$1,725.03	143	\$44,442.72	143
Transmission	800063834 Interconnection Study	\$2,391.07	143	\$39,008.17	143
Transmission	800063890 Interconnection Study	\$0.00	143	\$0.00	143
Transmission	800063939 Interconnection Study	\$97.39	143	\$0.00	143
Transmission	800063997 Interconnection Study	(\$3,562.52)	143	\$0.00	143
Transmission	800064009 Interconnection Study	\$338.61	143	\$22,954.02	143
Transmission	800064018 Interconnection Study	\$2,588.24	143	(\$17,068.28)	143
Transmission	800064265 Interconnection Study	\$537.75	143	(\$4,760.58)	143
Transmission	800064302 Interconnection Study	\$454.07	143	(\$3,922.41)	143
Transmission	800064304 Interconnection Study	\$690.41	143	\$0.00	143
Transmission	800064602 Interconnection Study	\$21.64	143	\$0.00	143
Transmission	800250922 Interconnection Study	\$2,679.93	143	(\$100,000.00)	143
Transmission	800259308 Interconnection Study	\$1,022.07	143	\$0.00	143
Transmission	800265425 Interconnection Study	(\$349.82)	143	\$305,000.00	143
Transmission	800293812 Interconnection Study	\$3,149.39	143	\$0.00	143
		\$11,783.26		\$285,653.64	

Schedule Page: 231 Line No.: 2 Column: b

Column B may NOT include A and G expenses for the entire period.

Schedule Page: 231 Line No.: 2 Column: d

Column D includes refunds that were paid to the interconnection customer in 2010 resulting from payments received exceeding actual study costs and includes interest payments on refunds. Multiple orders for the same project may net to actual payments/disbursements to customers.

Schedule Page: 231 Line No.: 22 Column: a

Project Type	Description	Costs Incurred During Period	Account Charged	Reimbursements received During Period	Account Charged with Reimbursements
Generation	800063812 Interconnection Study	(\$458.58)	143	\$51,269.06	143
Generation	800063813 Interconnection Study	(\$571.85)	143	\$41,189.23	143
Generation	800063821 Interconnection Study	\$6.70	143	\$0.00	143
Generation	800063857 Interconnection Study	\$26.43	143	\$0.00	143
Generation	800063858 Interconnection Study	\$3,277.55	143	\$0.00	143
Generation	800063880 Interconnection Study	(\$477.22)	143	\$12,129.31	143
Generation	800063882 Interconnection Study	\$274.44	143	(\$2,024.70)	143
Generation	800063888 Interconnection Study	\$78.40	143	\$0.00	143
Generation	800063897 Interconnection Study	\$1,827.22	143	\$36,519.62	143
Generation	800063900 Interconnection Study	\$6,324.13	143	\$0.00	143
Generation	800063901 Interconnection Study	\$2,374.62	143	\$0.00	143
Generation	800063912 Interconnection Study	\$19,884.97	143	(\$70,403.08)	143
Generation	800063940 Interconnection Study	\$3,153.96	143	(\$18,121.32)	143
Generation	800063958 Interconnection Study	\$12,108.87	143	(\$49,764.68)	143
Generation	800064036 Interconnection Study	\$12,737.12	143	(\$1,593.32)	143
Generation	800064062 Interconnection Study	\$9,374.78	143	\$31,118.30	143
Generation	800064065 Interconnection Study	\$1,101.60	143	\$0.00	143
Generation	800064072 Interconnection Study	\$133.53	143	(\$877.16)	143
Generation	800064077 Interconnection Study	\$20.00	143	(\$131.05)	143
Generation	800064079 Interconnection Study	\$324.53	143	\$0.00	143
Generation	800064114 Interconnection Study	\$13,426.77	143	\$0.00	143
Generation	800064136 Interconnection Study	\$567.64	143	\$0.00	143
Generation	800064165 Interconnection Study	\$5,783.81	143	\$0.00	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA

Generation	800064179 Interconnection Study	\$52.84	143	\$0.00	143
Generation	800064201 Interconnection Study	\$9,966.76	143	\$0.00	143
Generation	800064219 Interconnection Study	\$4,530.55	143	\$0.00	143
Generation	800064253 Interconnection Study	\$248.38	143	\$0.00	143
Generation	800064255 Interconnection Study	\$0.00	143	\$0.00	143
Generation	800064261 Interconnection Study	\$918.51	143	\$37,423.12	143
Generation	800064275 Interconnection Study	\$964.06	143	\$0.00	143
Generation	800064309 Interconnection Study	\$178.51	143	\$0.00	143
Generation	800064323 Interconnection Study	\$3,223.20	143	\$23,204.54	143
Generation	800064333 Interconnection Study	\$1,122.81	143	\$0.00	143
Generation	800064367 Interconnection Study	\$31.62	143	\$0.00	143
Generation	800064371 Interconnection Study	\$1,606.86	143	\$0.00	143
Generation	800064381 Interconnection Study	\$7,660.26	143	\$57,672.98	143
Generation	800064382 Interconnection Study	\$186.81	143	\$56,622.62	143
Generation	800064388 Interconnection Study	\$18,314.11	143	\$0.00	143
Generation	800064392 Interconnection Study	\$5,310.69	143	\$0.00	143
Generation	800064394 Interconnection Study	\$2,941.65	143	\$0.00	143
Generation	800064395 Interconnection Study	\$3,459.64	143	(\$5,932.83)	143
Generation	800064397 Interconnection Study	\$7,013.73	143	(\$26,994.38)	143
Generation	800064400 Interconnection Study	\$2,947.25	143	(\$3,744.27)	143
Generation	800064415 Interconnection Study	\$5.68	143	\$0.00	143
Generation	800064419 Interconnection Study	(\$464.45)	143	\$0.00	143
Generation	800064444 Interconnection Study	\$5,006.73	143	\$0.00	143
Generation	800064454 Interconnection Study	\$1,302.72	143	\$2,889.61	143
Generation	800064456 Interconnection Study	(\$472.41)	143	\$0.00	143
Generation	800064459 Interconnection Study	\$10,007.38	143	(\$45,354.64)	143
Generation	800064460 Interconnection Study	\$7,069.17	143	(\$34,411.88)	143
Generation	800064461 Interconnection Study	\$5,025.16	143	\$0.00	143
Generation	800064464 Interconnection Study	\$268.54	143	\$0.00	143
Generation	800064467 Interconnection Study	\$1,946.04	143	\$0.00	143
Generation	800064468 Interconnection Study	\$2,190.11	143	(\$10,837.00)	143
Generation	800064469 Interconnection Study	\$3,643.25	143	\$0.00	143
Generation	800064478 Interconnection Study	\$19,250.75	143	\$0.00	143
Generation	800064479 Interconnection Study	\$12,377.62	143	\$0.00	143
Generation	800064490 Interconnection Study	\$12.87	143	\$0.00	143
Generation	800064492 Interconnection Study	\$737.28	143	\$0.00	143
Generation	800064497 Interconnection Study	\$10,784.37	143	\$0.00	143
Generation	800064502 Interconnection Study	\$0.06	143	\$0.00	143
Generation	800064504 Interconnection Study	\$19,138.04	143	(\$42,415.39)	143
Generation	800064505 Interconnection Study	\$20,405.03	143	\$0.00	143
Generation	800064509 Interconnection Study	\$36,154.55	143	\$0.00	143
Generation	800064542 Interconnection Study	\$94.85	143	\$0.00	143
Generation	800064551 Interconnection Study	\$132.79	143	\$886.05	143
Generation	800064557 Interconnection Study	(\$1,149.93)	143	\$0.00	143
Generation	800064558 Interconnection Study	\$331.29	143	(\$2,383.18)	143
Generation	800064561 Interconnection Study	(\$856.86)	143	\$32,772.33	143
Generation	800064562 Interconnection Study	\$303.17	143	\$32,956.45	143
Generation	800064564 Interconnection Study	\$171.87	143	\$42,548.56	143
Generation	800064568 Interconnection Study	\$186.43	143	\$42,261.84	143
Generation	800064570 Interconnection Study	\$10,000.00	143	\$0.00	143
Generation	800064571 Interconnection Study	\$283.53	143	\$63,443.29	143
Generation	800064617 Interconnection Study	(\$2,707.03)	143	\$0.00	143
Generation	800064618 Interconnection Study	\$26.43	143	\$0.00	143
Generation	800064622 Interconnection Study	\$150.22	143	\$20.64	143
Generation	800064628 Interconnection Study	\$78.28	143	\$0.00	143
Generation	800064629 Interconnection Study	(\$0.13)	143	\$0.00	143
Generation	800112748 Interconnection Study	\$0.16	143	\$0.00	143
Generation	800112893 Interconnection Study	\$0.00	143	\$10,000.00	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Generation	800122470 Interconnection Study	\$366.62	143	\$37,210.54	143
Generation	800131316 Interconnection Study	\$14.77	143	\$10,599.32	143
Generation	800131318 Interconnection Study	\$146.06	143	\$9,561.07	143
Generation	800131400 Interconnection Study	\$14.77	143	\$10,596.27	143
Generation	800131401 Interconnection Study	\$0.00	143	\$10,000.00	143
Generation	800131404 Interconnection Study	\$0.00	143	\$10,645.43	143
Generation	800133488 Interconnection Study	\$0.00	143	\$10,000.00	143
Generation	800148455 Interconnection Study	\$1,714.82	143	\$94,392.29	143
Generation	800166422 Interconnection Study	\$151.57	143	(\$500.15)	143
Generation	800170354 Interconnection Study	\$4,710.88	143	\$0.00	143
Generation	800171178 Interconnection Study	\$2,856.01	143	\$0.00	143
Generation	800173286 Interconnection Study	\$4,456.65	143	\$0.00	143
Generation	800174485 Interconnection Study	(\$202.36)	143	\$0.00	143
Generation	800180673 Interconnection Study	\$31,029.02	143	\$0.00	143
Generation	800185608 Interconnection Study	\$870.92	143	(\$2,676.71)	143
Generation	800188386 Interconnection Study	\$244,957.91	143	\$0.00	143
Generation	800192635 Interconnection Study	\$2,212.03	143	\$0.00	143
Generation	800198619 Interconnection Study	\$1,118.66	143	\$0.00	143
Generation	800203892 Interconnection Study	\$12,523.62	143	\$0.00	143
Generation	800203893 Interconnection Study	\$30,620.99	143	\$0.00	143
Generation	800209976 Interconnection Study	(\$93,896.34)	143	\$0.00	143
Generation	800216012 Interconnection Study	\$2,742.36	143	\$0.00	143
Generation	800216366 Interconnection Study	\$710.90	143	\$0.00	143
Generation	800216376 Interconnection Study	\$1,655.68	143	\$0.00	143
Generation	800216377 Interconnection Study	\$51,983.75	143	\$240,000.00	143
Generation	800216400 Interconnection Study	\$1,884.74	143	\$0.00	143
Generation	800216402 Interconnection Study	\$1,884.74	143	\$0.00	143
Generation	800216403 Interconnection Study	\$15,017.23	143	\$240,000.00	143
Generation	800216405 Interconnection Study	\$15,237.83	143	\$240,000.00	143
Generation	800216407 Interconnection Study	\$16,867.13	143	\$0.00	143
Generation	800217401 Interconnection Study	\$2,761.35	143	\$0.00	143
Generation	800218670 Interconnection Study	\$268,363.87	143	\$0.00	143
Generation	800230360 Interconnection Study	\$4,629.80	143	(\$22,189.83)	143
Generation	800230478 Interconnection Study	\$30.69	143	\$0.00	143
Generation	800235311 Interconnection Study	\$11,989.19	143	\$0.00	143
Generation	800235318 Interconnection Study	\$12,540.56	143	\$0.00	143
Generation	800236081 Interconnection Study	\$27,219.47	143	\$0.00	143
Generation	800237729 Interconnection Study	\$7,452.86	143	\$0.00	143
Generation	800245246 Interconnection Study	\$1,662.23	143	(\$39,117.23)	143
Generation	800257247 Interconnection Study	\$211.37	143	\$0.00	143
Generation	800257562 Interconnection Study	\$33,633.04	143	\$0.00	143
Generation	800267516 Interconnection Study	\$2,284.62	143	(\$30,342.37)	143
Generation	800296902 Interconnection Study	\$3,595.41	143	\$0.00	143
Generation	800316346 Interconnection Study	\$1,769.60	143	(\$29,387.35)	143
Generation	800316527 Interconnection Study	\$1,769.60	143	(\$29,626.43)	143
Generation	800316528 Interconnection Study	\$2,063.51	143	(\$29,727.27)	143
Generation	800316530 Interconnection Study	\$1,928.14	143	(\$30,028.45)	143
Generation	800316532 Interconnection Study	\$1,899.38	143	(\$29,654.00)	143
Generation	800316535 Interconnection Study	\$1,796.75	143	(\$28,398.67)	143
Generation	800316538 Interconnection Study	\$1,718.46	143	(\$29,457.52)	143
Generation	800316539 Interconnection Study	\$1,769.60	143	(\$29,584.26)	143
Generation	800316563 Interconnection Study	\$1,769.60	143	(\$29,316.26)	143
Generation	800316567 Interconnection Study	\$1,718.46	143	(\$28,782.22)	143
Generation	800316568 Interconnection Study	\$1,769.60	143	(\$29,078.05)	143
Generation	800316571 Interconnection Study	\$1,716.12	143	(\$31,519.05)	143
Generation	800316573 Interconnection Study	\$1,770.21	143	(\$29,719.42)	143
Generation	800316574 Interconnection Study	\$1,835.88	143	(\$29,920.72)	143
Generation	800316575 Interconnection Study	\$1,591.58	143	(\$30,532.94)	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Generation	800316576 Interconnection Study	\$1,769.60	143	(\$29,497.92)	143
Generation	800316580 Interconnection Study	\$1,886.40	143	(\$29,627.98)	143
Generation	800316682 Interconnection Study	\$1,722.96	143	(\$28,704.53)	143
Generation	800316683 Interconnection Study	\$1,778.78	143	(\$30,347.37)	143
Generation	800316684 Interconnection Study	\$3,753.71	143	(\$33,167.89)	143
Generation	800316688 Interconnection Study	\$1,769.60	143	(\$30,417.50)	143
Generation	800316691 Interconnection Study	\$1,536.14	143	(\$30,113.74)	143
Generation	800316774 Interconnection Study	\$2,646.89	143	(\$31,908.18)	143
Generation	800316823 Interconnection Study	\$2,422.05	143	(\$29,979.54)	143
Generation	800316827 Interconnection Study	\$1,769.60	143	(\$29,782.92)	143
Generation	800316830 Interconnection Study	\$2,742.79	143	(\$31,719.07)	143
Generation	800316836 Interconnection Study	\$1,953.66	143	(\$33,076.19)	143
Generation	800316880 Interconnection Study	\$1,013.41	143	\$0.00	143
Generation	800317250 Interconnection Study	\$2,652.92	143	(\$29,996.60)	143
Generation	800317254 Interconnection Study	\$2,047.89	143	(\$30,195.06)	143
Generation	800317256 Interconnection Study	\$1,805.28	143	(\$29,603.87)	143
Generation	800317259 Interconnection Study	\$1,769.60	143	(\$29,862.22)	143
Generation	800317361 Interconnection Study	\$1,804.32	143	(\$29,889.40)	143
Generation	800317363 Interconnection Study	\$3,697.67	143	(\$32,924.83)	143
Generation	800317364 Interconnection Study	\$1,900.48	143	(\$32,807.12)	143
Generation	800317379 Interconnection Study	\$1,770.82	143	(\$30,471.47)	143
Generation	800317425 Interconnection Study	\$1,718.46	143	(\$30,007.73)	143
Generation	800317426 Interconnection Study	\$1,996.75	143	(\$30,337.26)	143
Generation	800317427 Interconnection Study	\$2,116.38	143	(\$30,798.84)	143
Generation	800317431 Interconnection Study	\$1,718.46	143	(\$29,617.86)	143
Generation	800317432 Interconnection Study	\$1,861.50	143	(\$29,272.33)	143
Generation	800317436 Interconnection Study	\$1,718.46	143	(\$28,920.65)	143
Generation	800317438 Interconnection Study	\$1,769.60	143	(\$28,489.21)	143
Generation	800317439 Interconnection Study	\$2,066.48	143	(\$31,130.99)	143
Generation	800317455 Interconnection Study	\$1,556.79	143	(\$29,485.74)	143
Generation	800317457 Interconnection Study	\$2,097.94	143	(\$29,524.13)	143
Generation	800317458 Interconnection Study	\$1,904.62	143	(\$29,519.52)	143
Generation	800317459 Interconnection Study	\$1,769.60	143	(\$30,827.62)	143
Generation	800317460 Interconnection Study	\$1,907.20	143	(\$31,272.63)	143
Generation	800317461 Interconnection Study	\$1,838.44	143	(\$30,659.61)	143
Generation	800317462 Interconnection Study	\$1,769.60	143	(\$28,458.03)	143
Generation	800317541 Interconnection Study	\$2,066.51	143	(\$32,718.60)	143
Generation	800317542 Interconnection Study	\$1,935.04	143	(\$32,258.34)	143
Generation	800317543 Interconnection Study	\$2,189.22	143	(\$31,227.76)	143
Generation	800317545 Interconnection Study	\$2,075.70	143	(\$28,995.06)	143
Generation	800317548 Interconnection Study	\$1,891.26	143	(\$28,995.60)	143
Generation	800317552 Interconnection Study	\$1,943.20	143	(\$29,160.93)	143
Generation	800317553 Interconnection Study	\$2,101.84	143	(\$29,899.86)	143
Generation	800317554 Interconnection Study	\$1,860.74	143	(\$30,481.22)	143
Generation	800317555 Interconnection Study	\$3,985.61	143	(\$35,425.95)	143
Generation	800317556 Interconnection Study	\$1,879.90	143	(\$33,904.39)	143
Generation	800317599 Interconnection Study	\$1,996.71	143	(\$31,255.01)	143
Generation	800317621 Interconnection Study	\$1,964.55	143	(\$30,301.71)	143
Generation	800321967 Interconnection Study	\$1,887.79	143	\$0.00	143
Generation	800322270 Interconnection Study	(\$204.27)	143	\$0.00	143
Generation	800329589 Interconnection Study	\$376.84	143	(\$1,438.89)	143
Generation	800333181 Interconnection Study	\$128.46	143	\$476.77	143
Generation	800334674 Interconnection Study	\$5,402.36	143	\$0.00	143
Generation	800334725 Interconnection Study	\$1,075.12	143	\$0.00	143
Generation	800337921 Interconnection Study	\$54.43	143	\$544.05	143
Generation	800337924 Interconnection Study	\$210.66	143	(\$15.57)	143
Generation	800337925 Interconnection Study	\$288.04	143	(\$295.16)	143
Generation	800339372 Interconnection Study	\$14,812.11	143	\$0.00	143

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Generation	800339713 Interconnection Study	\$15,769.22	143	\$0.00	143
Generation	800340766 Interconnection Study	(\$203.37)	143	\$0.00	143
Generation	800340767 Interconnection Study	\$11,212.46	143	\$0.00	143
Generation	800340768 Interconnection Study	(\$142.34)	143	(\$2,122.29)	143
Generation	800342743 Interconnection Study	\$186,662.76	143	\$0.00	143
Generation	800345324 Interconnection Study	\$1,612.83	143	\$0.00	143
Generation	800345338 Interconnection Study	\$11,875.05	143	\$0.00	143
Generation	800345480 Interconnection Study	\$6,845.16	143	(\$30,753.83)	143
Generation	800345481 Interconnection Study	\$7,487.33	143	(\$27,069.45)	143
Generation	800345482 Interconnection Study	\$8,408.98	143	(\$27,242.44)	143
Generation	800345483 Interconnection Study	\$7,487.86	143	(\$26,718.71)	143
Generation	800347455 Interconnection Study	\$63,956.55	143	\$250,000.00	143
Generation	800347464 Interconnection Study	(\$202.36)	143	\$0.00	143
Generation	800347465 Interconnection Study	\$18,654.24	143	\$0.00	143
Generation	800347466 Interconnection Study	(\$72.18)	143	\$0.00	143
Generation	800348926 Interconnection Study	\$12,682.29	143	\$0.00	143
Generation	800348928 Interconnection Study	\$12,789.98	143	\$0.00	143
Generation	800348936 Interconnection Study	(\$202.36)	143	\$0.00	143
Generation	800348938 Interconnection Study	\$6,471.70	143	(\$29,686.32)	143
Generation	800349044 Interconnection Study	(\$27.05)	143	(\$2,520.66)	143
Generation	800349045 Interconnection Study	\$808.17	143	(\$579.01)	143
Generation	800349364 Interconnection Study	\$11,470.12	143	\$0.00	143
Generation	800349365 Interconnection Study	\$11,552.12	143	\$0.00	143
Generation	800349366 Interconnection Study	\$11,796.20	143	\$0.00	143
Generation	800351586 Interconnection Study	\$27,009.90	143	\$0.00	143
Generation	800353364 Interconnection Study	\$11,758.15	143	\$0.00	143
Generation	800353621 Interconnection Study	\$0.00	143	\$0.00	143
Generation	800353903 Interconnection Study	\$7,405.49	143	\$0.00	143
Generation	800355959 Interconnection Study	\$1,453.32	143	\$0.00	143
Generation	800356739 Interconnection Study	\$234,262.82	143	\$0.00	143
Generation	800357709 Interconnection Study	\$3,410.70	143	\$0.00	143
Generation	800358037 Interconnection Study	\$417.50	143	\$0.00	143
Generation	800358038 Interconnection Study	\$789.46	143	\$0.00	143
Generation	800358053 Interconnection Study	\$609.72	143	\$0.00	143
Generation	800358279 Interconnection Study	\$302.78	143	(\$498.86)	143
Generation	800358562 Interconnection Study	\$225.72	143	\$569.67	143
Generation	800359898 Interconnection Study	\$246.38	143	\$0.00	143
Generation	800360167 Interconnection Study	\$577.47	143	\$0.00	143
Generation	800361495 Interconnection Study	\$452.28	143	\$4,438.90	143
Generation	800361497 Interconnection Study	\$2,501.03	143	(\$4,787.06)	143
Generation	800361560 Interconnection Study	\$1,032.99	143	\$0.00	143
Generation	800361561 Interconnection Study	\$575.84	143	\$0.00	143
Generation	800361563 Interconnection Study	\$575.84	143	\$0.00	143
Generation	800361568 Interconnection Study	\$197.25	143	\$0.00	143
Generation	800361570 Interconnection Study	\$222.73	143	\$0.00	143
Generation	800361571 Interconnection Study	\$220.90	143	\$0.00	143
Generation	800363529 Interconnection Study	\$159.80	143	\$422.97	143
Generation	800363531 Interconnection Study	(\$1,039.75)	143	\$8,662.72	143
Generation	800363532 Interconnection Study	\$1,013.35	143	\$7,841.73	143
Generation	800363534 Interconnection Study	\$146.09	143	\$0.00	143
Generation	800363536 Interconnection Study	\$1,100.34	143	\$0.00	143
Generation	800363539 Interconnection Study	\$197.03	143	\$0.00	143
Generation	800363581 Interconnection Study	\$220.70	143	\$0.00	143
Generation	800363661 Interconnection Study	\$197.05	143	\$0.00	143
Generation	800363663 Interconnection Study	\$486.96	143	\$0.00	143
Generation	800363665 Interconnection Study	\$510.92	143	\$9,133.01	143
Generation	800363666 Interconnection Study	\$343.42	143	\$9,910.11	143
Generation	800364482 Interconnection Study	\$429.95	143	\$9,633.59	143

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Generation	800367588 Interconnection Study	\$105.68	143	\$0.00	143
Generation	800367920 Interconnection Study	\$713.02	143	\$0.00	143
Generation	800367923 Interconnection Study	\$591.82	143	\$0.00	143
Generation	800367927 Interconnection Study	\$216.32	143	\$0.00	143
Generation	800367928 Interconnection Study	\$41.53	143	\$0.00	143
Generation	800368214 Interconnection Study	\$140.08	143	\$0.00	143
Generation	800368564 Interconnection Study	\$383.70	143	(\$874.23)	143
Generation	800368678 Interconnection Study	\$2,858.52	143	\$0.00	143
Generation	800370501 Interconnection Study	\$859.87	143	\$0.00	143
Generation	800370502 Interconnection Study	\$690.79	143	\$0.00	143
Generation	800371004 Interconnection Study	\$138.18	143	\$0.00	143
Generation	800375711 Interconnection Study	\$1,906.61	143	\$0.00	143
Generation	800375712 Interconnection Study	\$15,461.05	143	\$0.00	143
Generation	800375713 Interconnection Study	\$46.49	143	(\$203.40)	143
Generation	800383268 Interconnection Study	\$761.94	143	(\$1,758.69)	143
Generation	800386291 Interconnection Study	\$452.27	143	(\$400.50)	143
Generation	800396360 Interconnection Study	\$66.16	143	\$0.00	143
Generation	800396363 Interconnection Study	\$66.16	143	\$0.00	143
Generation	800396367 Interconnection Study	\$4,363.03	143	\$0.00	143
Generation	800396370 Interconnection Study	\$66.16	143	\$0.00	143
Generation	800396371 Interconnection Study	\$2,662.06	143	\$0.00	143
Generation	800398894 Interconnection Study	\$2,762.66	143	\$0.00	143
Generation	800401195 Interconnection Study	\$419.89	143	\$0.00	143
Generation	800404791 Interconnection Study	\$1,050.86	143	\$0.00	143
Generation	800404792 Interconnection Study	\$216.69	143	(\$162.94)	143
Generation	800405124 Interconnection Study	(\$597,192.46)	143	\$0.00	143
Generation	800406428 Interconnection Study	\$141.28	143	\$10,517.31	143
Generation	800406432 Interconnection Study	\$144.18	143	(\$691.26)	143
Generation	800406435 Interconnection Study	\$632.18	143	\$0.00	143
Generation	800406436 Interconnection Study	\$430.91	143	\$0.00	143
Generation	800408657 Interconnection Study	\$21,006.72	143	\$0.00	143
Generation	800408829 Interconnection Study	\$545.18	143	\$0.00	143
Generation	800410543 Interconnection Study	\$62,094.44	143	\$0.00	143
Generation	800410545 Interconnection Study	\$1,954.92	143	(\$2,838.41)	143
Generation	800413133 Interconnection Study	\$22,625.59	143	\$0.00	143
Generation	800413138 Interconnection Study	\$29,330.97	143	\$0.00	143
Generation	800413139 Interconnection Study	\$27,195.78	143	\$0.00	143
Generation	800414086 Interconnection Study	\$2,980.02	143	\$0.00	143
Generation	800414087 Interconnection Study	\$2,293.71	143	\$0.00	143
Generation	800414088 Interconnection Study	\$2,331.11	143	\$0.00	143
Generation	800414089 Interconnection Study	\$109.81	143	\$0.00	143
Generation	800414090 Interconnection Study	\$1,427.59	143	\$0.00	143
Generation	800414091 Interconnection Study	\$173.52	143	\$0.00	143
Generation	800414092 Interconnection Study	\$468.17	143	\$0.00	143
Generation	800414322 Interconnection Study	\$2,902.67	143	\$0.00	143
Generation	800414323 Interconnection Study	\$725.30	143	\$0.00	143
Generation	800414324 Interconnection Study	\$1,469.70	143	\$0.00	143
Generation	800414501 Interconnection Study	\$52,018.62	143	\$0.00	143
Generation	800416937 Interconnection Study	\$6,345.71	143	\$0.00	143
Generation	800417584 Interconnection Study	\$136.70	143	(\$664.11)	143
Generation	800417585 Interconnection Study	\$2,131.61	143	(\$2,314.12)	143
Generation	800417587 Interconnection Study	\$334.84	143	\$0.00	143
Generation	800417588 Interconnection Study	\$565.16	143	(\$684.00)	143
Generation	800417589 Interconnection Study	\$1,547.03	143	(\$3,420.00)	143
Generation	800417590 Interconnection Study	\$565.16	143	(\$684.00)	143
Generation	800419569 Interconnection Study	\$4,932.79	143	(\$10,943.07)	143
Generation	800419570 Interconnection Study	\$1,704.78	143	(\$1,765.92)	143
Generation	800422913 Interconnection Study	\$362.27	143	(\$215.60)	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA

Generation	800422914 Interconnection Study	\$1,002.43	143	(\$600.00)	143
Generation	800422915 Interconnection Study	\$2,535.99	143	\$4,431.94	143
Generation	800422916 Interconnection Study	\$201.07	143	\$5,578.91	143
Generation	800422917 Interconnection Study	\$1,141.79	143	\$4,041.52	143
Generation	800423311 Interconnection Study	\$82.41	143	\$723.46	143
Generation	800425794 Interconnection Study	\$12,312.33	143	\$0.00	143
Generation	800430357 Interconnection Study	\$514.18	143	\$0.00	143
Generation	800430404 Interconnection Study	\$1,156.92	143	\$0.00	143
Generation	800430536 Interconnection Study	\$663.82	143	\$0.00	143
Generation	800430537 Interconnection Study	\$621.98	143	\$0.00	143
Generation	800430538 Interconnection Study	\$2,333.15	143	\$0.00	143
Generation	800430539 Interconnection Study	\$2,236.53	143	\$0.00	143
Generation	800430820 Interconnection Study	\$5,247.63	143	\$0.00	143
Generation	800432244 Interconnection Study	\$4,501.73	143	\$0.00	143
Generation	800432245 Interconnection Study	\$1,741.96	143	\$0.00	143
Generation	800432246 Interconnection Study	\$502.31	143	\$0.00	143
Generation	800432247 Interconnection Study	\$8,689.17	143	\$0.00	143
Generation	800433636 Interconnection Study	\$1,299.45	143	(\$1,276.41)	143
Generation	800433637 Interconnection Study	\$1,272.07	143	(\$1,198.89)	143
Generation	800440564 Interconnection Study	\$1,138.22	143	\$0.00	143
Generation	800440565 Interconnection Study	\$253.23	143	(\$233.88)	143
Generation	800440566 Interconnection Study	\$1,138.22	143	\$0.00	143
Generation	800440567 Interconnection Study	\$549.97	143	(\$507.95)	143
Generation	800442264 Interconnection Study	\$1,629.48	143	\$0.00	143
Generation	800442265 Interconnection Study	\$2,068.29	143	(\$1,979.17)	143
Generation	800445081 Interconnection Study	\$696.04	143	(\$3,213.10)	143
Generation	800445082 Interconnection Study	\$1,090.17	143	(\$3,800.00)	143
Generation	800445083 Interconnection Study	\$1,514.95	143	(\$6,800.00)	143
Generation	800445333 Interconnection Study	\$14,747.59	143	\$0.00	143
Generation	800446196 Interconnection Study	\$1,683.31	143	(\$11,000.00)	143
Generation	800446197 Interconnection Study	\$72,037.33	143	\$0.00	143
Generation	800448306 Interconnection Study	\$2,922.50	143	(\$9,000.00)	143
Generation	800448313 Interconnection Study	\$1,639.93	143	(\$12,200.00)	143
Generation	800448386 Interconnection Study	\$655.89	143	(\$1,184.00)	143
Generation	800448522 Interconnection Study	\$856.78	143	(\$1,184.00)	143
Generation	800448740 Interconnection Study	\$2,881.57	143	(\$9,416.12)	143
Generation	800449369 Interconnection Study	\$6,576.90	143	\$0.00	143
Generation	800449371 Interconnection Study	\$998.48	143	\$0.00	143
Generation	800451183 Interconnection Study	\$185.45	143	(\$1,200.00)	143
Generation	800451184 Interconnection Study	\$1,663.91	143	(\$900.00)	143
Generation	800451185 Interconnection Study	\$1,508.26	143	(\$1,000.00)	143
Generation	800451186 Interconnection Study	\$1,682.15	143	(\$1,200.00)	143
Generation	800451187 Interconnection Study	\$74,565.65	143	\$0.00	143
Generation	800451188 Interconnection Study	\$2,390.44	143	\$3,382.03	143
Generation	800451189 Interconnection Study	\$63,935.53	143	(\$300,000.00)	143
Generation	800452100 Interconnection Study	\$64,276.64	143	(\$262,000.00)	143
Generation	800452220 Interconnection Study	(\$1,114.21)	143	\$0.00	143
Generation	800452224 Interconnection Study	\$69,976.04	143	(\$520,000.00)	143
Generation	800452225 Interconnection Study	\$741.19	143	(\$1,184.00)	143
Generation	800452227 Interconnection Study	\$4,568.85	143	(\$5,442.46)	143
Generation	800452229 Interconnection Study	\$71,260.99	143	\$0.00	143
Generation	800452641 Interconnection Study	\$71,620.44	143	\$0.00	143
Generation	800452645 Interconnection Study	\$72,283.69	143	\$0.00	143
Generation	800452769 Interconnection Study	\$71,092.28	143	\$0.00	143
Generation	800452770 Interconnection Study	\$71,192.03	143	\$0.00	143
Generation	800452771 Interconnection Study	\$36,578.49	143	(\$315,000.00)	143
Generation	800453807 Interconnection Study	\$1,188.82	143	\$0.00	143
Generation	800453812 Interconnection Study	(\$176.45)	143	(\$1,121.91)	143

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Generation	800453980 Interconnection Study	\$73,375.21	143	\$0.00	143
Generation	800453982 Interconnection Study	\$71,467.32	143	\$0.00	143
Generation	800453984 Interconnection Study	\$461.38	143	(\$1,380.22)	143
Generation	800454772 Interconnection Study	\$71,838.12	143	\$0.00	143
Generation	800454774 Interconnection Study	\$71,824.25	143	\$0.00	143
Generation	800454776 Interconnection Study	\$1,873.80	143	(\$1,841.28)	143
Generation	800454778 Interconnection Study	\$71,960.37	143	\$0.00	143
Generation	800454779 Interconnection Study	\$72,412.68	143	\$0.00	143
Generation	800454861 Interconnection Study	\$159.94	143	(\$1,421.56)	143
Generation	800454862 Interconnection Study	\$500.89	143	(\$1,798.87)	143
Generation	800454942 Interconnection Study	\$779.56	143	(\$7,840.00)	143
Generation	800457334 Interconnection Study	\$1,846.17	143	\$0.00	143
Generation	800460066 Interconnection Study	\$252.37	143	\$0.00	143
Generation	800460067 Interconnection Study	\$1,184.73	143	(\$7,000.00)	143
Generation	800460068 Interconnection Study	\$1,341.24	143	(\$7,000.00)	143
Generation	800460070 Interconnection Study	\$465.52	143	\$0.00	143
Generation	800460071 Interconnection Study	\$3,332.48	143	\$0.00	143
Generation	800460072 Interconnection Study	\$3,296.18	143	\$0.00	143
Generation	800460073 Interconnection Study	\$2,373.10	143	(\$2,161.64)	143
Generation	800460074 Interconnection Study	\$2,081.19	143	(\$1,871.58)	143
Generation	800460076 Interconnection Study	\$1,861.51	143	(\$1,793.63)	143
Generation	800460077 Interconnection Study	\$3,860.29	143	(\$1,000.00)	143
Generation	800460078 Interconnection Study	\$3,003.51	143	(\$1,000.00)	143
Generation	800460079 Interconnection Study	\$5,142.30	143	(\$1,000.00)	143
Generation	800460120 Interconnection Study	\$29,005.12	143	\$0.00	143
Generation	800460121 Interconnection Study	\$1,136.86	143	(\$1,000.00)	143
Generation	800460122 Interconnection Study	\$103.70	143	(\$3,182.00)	143
Generation	800460123 Interconnection Study	\$1,000.93	143	(\$1,200.00)	143
Generation	800460124 Interconnection Study	\$26,514.61	143	(\$50,000.00)	143
Generation	800460125 Interconnection Study	\$648.27	143	(\$10,000.00)	143
Generation	800460127 Interconnection Study	\$771.01	143	(\$4,200.00)	143
Generation	800460128 Interconnection Study	\$863.07	143	(\$4,200.00)	143
Generation	800460129 Interconnection Study	\$115.11	143	(\$1,160.00)	143
Generation	800460130 Interconnection Study	\$1,240.45	143	(\$1,480.00)	143
Generation	800460131 Interconnection Study	\$1,784.83	143	(\$1,320.00)	143
Generation	800460132 Interconnection Study	\$492.58	143	(\$1,320.00)	143
Generation	800460133 Interconnection Study	\$519.05	143	(\$1,320.00)	143
Generation	800460134 Interconnection Study	\$615.01	143	(\$244.25)	143
Generation	800460135 Interconnection Study	\$1,403.41	143	(\$956.41)	143
Generation	800460136 Interconnection Study	\$1,284.45	143	(\$921.14)	143
Generation	800460137 Interconnection Study	\$1,611.52	143	(\$934.99)	143
Generation	800469444 Interconnection Study	\$571.06	143	(\$1,000.00)	143
Generation	800469446 Interconnection Study	\$1,247.46	143	(\$1,209.65)	143
Generation	800469448 Interconnection Study	\$9,641.57	143	(\$50,000.00)	143
Generation	800469450 Interconnection Study	\$390.45	143	\$0.00	143
Generation	800469451 Interconnection Study	\$12,072.53	143	(\$50,000.00)	143
Generation	800469452 Interconnection Study	\$3,098.46	143	(\$4,420.00)	143
Generation	800469453 Interconnection Study	\$3,616.47	143	(\$4,078.00)	143
Generation	800469455 Interconnection Study	\$448.49	143	\$0.00	143
Generation	800469456 Interconnection Study	\$743.89	143	(\$9,100.00)	143
Generation	800469457 Interconnection Study	\$24,690.68	143	(\$1,000.00)	143
Generation	800469458 Interconnection Study	\$7,517.79	143	(\$1,000.00)	143
Generation	800469459 Interconnection Study	\$423.83	143	(\$2,600.00)	143
Generation	800469460 Interconnection Study	\$1,321.95	143	(\$4,200.00)	143
Generation	800469461 Interconnection Study	\$2,046.72	143	\$0.00	143
Generation	800469462 Interconnection Study	\$2,189.68	143	\$0.00	143
Generation	800475843 Interconnection Study	\$526.01	143	\$0.00	143
Generation	800475844 Interconnection Study	\$1,479.23	143	\$0.00	143

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Generation	800475846 Interconnection Study	\$1,110.14	143	(\$968.00)	143
Generation	800476542 Interconnection Study	\$1,353.17	143	(\$734.00)	143
Generation	800476543 Interconnection Study	\$1,188.32	143	(\$756.00)	143
Generation	800476544 Interconnection Study	\$1,157.61	143	(\$724.00)	143
Generation	800476545 Interconnection Study	\$5,012.83	143	(\$778.00)	143
Generation	800476546 Interconnection Study	\$462.31	143	(\$1,378.00)	143
Generation	800476547 Interconnection Study	\$485.41	143	(\$826.00)	143
Generation	800476548 Interconnection Study	\$462.31	143	(\$1,016.00)	143
Generation	800476549 Interconnection Study	\$1,182.78	143	(\$808.00)	143
Generation	800476550 Interconnection Study	\$460.06	143	(\$1,364.00)	143
Generation	800476551 Interconnection Study	\$895.49	143	(\$1,332.00)	143
Generation	800476552 Interconnection Study	\$472.03	143	(\$896.00)	143
Generation	800476553 Interconnection Study	\$519.68	143	(\$870.00)	143
Generation	800476554 Interconnection Study	\$447.54	143	(\$994.00)	143
Generation	800476555 Interconnection Study	\$447.54	143	(\$882.00)	143
Generation	800476556 Interconnection Study	\$1,150.32	143	(\$728.00)	143
Generation	800476557 Interconnection Study	\$276.17	143	(\$744.00)	143
Generation	800476558 Interconnection Study	\$650.76	143	(\$972.60)	143
Generation	800476559 Interconnection Study	\$426.48	143	(\$1,003.96)	143
Generation	800476760 Interconnection Study	\$201.07	143	(\$1,036.82)	143
Generation	800476761 Interconnection Study	\$210.62	143	(\$1,023.62)	143
Generation	800476762 Interconnection Study	\$210.62	143	(\$1,176.76)	143
Generation	800476763 Interconnection Study	\$210.62	143	(\$900.82)	143
Generation	800476764 Interconnection Study	\$210.62	143	(\$1,214.76)	143
Generation	800476765 Interconnection Study	\$7,761.90	143	\$0.00	143
Generation	800476766 Interconnection Study	\$5,335.37	143	\$0.00	143
Generation	800476767 Interconnection Study	\$775.00	143	(\$1,128.00)	143
Generation	800476770 Interconnection Study	\$695.42	143	(\$1,198.00)	143
Generation	800476771 Interconnection Study	\$375.69	143	(\$1,360.00)	143
Generation	800476773 Interconnection Study	\$346.23	143	(\$860.00)	143
Generation	800476775 Interconnection Study	\$20,144.95	143	(\$50,000.00)	143
Generation	800476777 Interconnection Study	\$35,487.15	143	(\$50,000.00)	143
Generation	800476778 Interconnection Study	\$30,561.63	143	(\$50,000.00)	143
Generation	800476782 Interconnection Study	\$1,165.11	143	(\$12,200.00)	143
Generation	800476783 Interconnection Study	\$2,499.79	143	(\$4,070.75)	143
Generation	800476784 Interconnection Study	\$535.16	143	(\$2,062.09)	143
Generation	800476785 Interconnection Study	\$353.48	143	(\$1,260.00)	143
Generation	800476786 Interconnection Study	\$111.79	143	(\$1,260.00)	143
Generation	800476787 Interconnection Study	\$111.79	143	(\$1,260.00)	143
Generation	800476788 Interconnection Study	\$111.79	143	(\$1,260.00)	143
Generation	800476789 Interconnection Study	\$111.79	143	(\$1,260.00)	143
Generation	800492293 Interconnection Study	\$111.79	143	(\$1,260.00)	143
Generation	800492295 Interconnection Study	\$133.48	143	(\$1,260.00)	143
Generation	800492296 Interconnection Study	\$133.48	143	(\$1,260.00)	143
Generation	800492297 Interconnection Study	\$133.48	143	(\$1,260.00)	143
Generation	800492298 Interconnection Study	\$882.79	143	(\$1,500.00)	143
Generation	800492299 Interconnection Study	\$2,371.33	143	(\$8,000.00)	143
Generation	800492400 Interconnection Study	\$297.02	143	(\$1,067.80)	143
Generation	800492402 Interconnection Study	\$271.46	143	(\$1,067.80)	143
Generation	800492403 Interconnection Study	\$271.04	143	(\$1,067.80)	143
Generation	800492404 Interconnection Study	\$70,745.33	143	\$0.00	143
Generation	800492405 Interconnection Study	\$167.30	143	(\$1,800.00)	143
Generation	800492407 Interconnection Study	\$167.30	143	(\$1,300.00)	143
Generation	800492411 Interconnection Study	\$1,740.46	143	(\$2,869.51)	143
Generation	800492412 Interconnection Study	\$126.03	143	(\$1,763.84)	143
Generation	800492413 Interconnection Study	\$133.48	143	(\$2,678.71)	143
Generation	800492414 Interconnection Study	\$133.48	143	(\$4,029.75)	143
Generation	800492415 Interconnection Study	\$133.48	143	(\$2,360.88)	143

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Generation	800492416 Interconnection Study	\$265.71	143	(\$2,782.31)	143
Generation	800492418 Interconnection Study	\$133.48	143	(\$4,089.47)	143
Generation	800492419 Interconnection Study	\$133.48	143	(\$2,368.40)	143
Generation	800492441 Interconnection Study	\$133.48	143	(\$2,322.27)	143
Generation	800492442 Interconnection Study	\$627.29	143	(\$1,000.00)	143
Generation	800492443 Interconnection Study	\$133.48	143	(\$1,000.00)	143
Generation	800492444 Interconnection Study	\$133.48	143	(\$1,000.00)	143
Generation	800492445 Interconnection Study	\$249.61	143	(\$1,420.00)	143
Generation	800492446 Interconnection Study	\$133.48	143	(\$788.00)	143
Generation	800492447 Interconnection Study	\$167.30	143	(\$1,420.00)	143
Generation	800492448 Interconnection Study	\$133.48	143	(\$2,265.08)	143
Generation	800492449 Interconnection Study	\$133.48	143	(\$2,418.82)	143
Generation	800492450 Interconnection Study	\$295.65	143	(\$2,800.00)	143
Generation	800492451 Interconnection Study	\$296.08	143	\$0.00	143
Generation	800492453 Interconnection Study	\$254.05	143	(\$763.00)	143
Generation	800492454 Interconnection Study	\$133.48	143	(\$1,000.00)	143
Generation	800492456 Interconnection Study	\$41,831.97	143	(\$50,000.00)	143
Generation	800492457 Interconnection Study	\$6,593.24	143	(\$1,000.00)	143
Generation	800492458 Interconnection Study	\$1,632.17	143	(\$1,000.00)	143
Generation	800497876 Interconnection Study	\$601.35	143	(\$9,000.00)	143
Generation	800497877 Interconnection Study	\$600.79	143	\$0.00	143
Generation	800497878 Interconnection Study	\$0.00	143	(\$1,500.00)	143
Generation	800497940 Interconnection Study	\$0.00	143	(\$1,500.00)	143
Generation	800497941 Interconnection Study	\$0.00	143	(\$900.00)	143
Generation	800497942 Interconnection Study	\$52.51	143	(\$6,250.00)	143
Generation	800497943 Interconnection Study	\$905.60	143	(\$4,762.00)	143
Generation	800497944 Interconnection Study	\$6,918.05	143	\$0.00	143
Generation	800497945 Interconnection Study	\$6,107.46	143	\$0.00	143
Generation	800497946 Interconnection Study	\$3,499.75	143	(\$22,500.00)	143
Generation	800497947 Interconnection Study	\$14,003.50	143	(\$50,000.00)	143
Generation	800497948 Interconnection Study	\$3,605.13	143	(\$25,000.00)	143
Generation	800497949 Interconnection Study	\$276.53	143	(\$25,000.00)	143
Generation	800497950 Interconnection Study	\$4,558.85	143	(\$25,000.00)	143
Generation	800498458 Interconnection Study	\$6,176.88	143	(\$25,000.00)	143
Generation	800498502 Interconnection Study	\$15,145.73	143	(\$25,000.00)	143
Generation	800498504 Interconnection Study	\$270.09	143	(\$25,000.00)	143
Generation	800498508 Interconnection Study	\$3,257.76	143	(\$25,000.00)	143
Generation	800498509 Interconnection Study	\$243.66	143	(\$25,000.00)	143
Generation	800498511 Interconnection Study	\$244.04	143	(\$25,000.00)	143
Generation	800498512 Interconnection Study	\$4,108.62	143	(\$25,000.00)	143
Generation	800498513 Interconnection Study	\$46.88	143	(\$4,200.00)	143
Generation	800498514 Interconnection Study	\$1,773.35	143	(\$37,500.00)	143
Generation	800498516 Interconnection Study	\$194.54	143	(\$1,400.00)	143
Generation	800509541 Interconnection Study	\$195.82	143	(\$1,400.00)	143
Generation	800509542 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509543 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509544 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509545 Interconnection Study	\$0.00	143	(\$1,400.00)	143
Generation	800509546 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509547 Interconnection Study	\$52.51	143	(\$1,750.00)	143
Generation	800509548 Interconnection Study	\$169.84	143	(\$1,400.00)	143
Generation	800509549 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509550 Interconnection Study	\$181.72	143	(\$1,400.00)	143
Generation	800509551 Interconnection Study	\$172.00	143	(\$1,400.00)	143
Generation	800509552 Interconnection Study	\$52.51	143	(\$1,750.00)	143
Generation	800509553 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800509554 Interconnection Study	\$829.28	143	(\$1,400.00)	143
Generation	800509555 Interconnection Study	\$8,939.15	143	\$0.00	143

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Generation	800509557 Interconnection Study	\$247.11	143	\$0.00	143
Generation	800509559 Interconnection Study	\$247.11	143	\$0.00	143
Generation	800509580 Interconnection Study	\$247.11	143	\$0.00	143
Generation	800509581 Interconnection Study	\$247.11	143	\$0.00	143
Generation	800509582 Interconnection Study	\$1,772.64	143	(\$1,000.00)	143
Generation	800509583 Interconnection Study	\$717.62	143	(\$1,800.00)	143
Generation	800509584 Interconnection Study	\$893.54	143	(\$3,000.00)	143
Generation	800509585 Interconnection Study	\$1,060.50	143	(\$5,000.00)	143
Generation	800509586 Interconnection Study	\$939.61	143	(\$1,800.00)	143
Generation	800509587 Interconnection Study	\$607.13	143	(\$25,000.00)	143
Generation	800509588 Interconnection Study	\$5,599.24	143	(\$25,000.00)	143
Generation	800509589 Interconnection Study	\$317.40	143	(\$4,500.00)	143
Generation	800510484 Interconnection Study	\$169.08	143	(\$2,500.00)	143
Generation	800510485 Interconnection Study	\$147.26	143	(\$5,000.00)	143
Generation	800510486 Interconnection Study	\$3,670.71	143	(\$964.00)	143
Generation	800510487 Interconnection Study	\$219.73	143	(\$1,000.00)	143
Generation	800510488 Interconnection Study	\$682.08	143	(\$5,700.00)	143
Generation	800510489 Interconnection Study	\$770.51	143	(\$8,060.00)	143
Generation	800510490 Interconnection Study	\$387.54	143	(\$12,460.00)	143
Generation	800510491 Interconnection Study	\$58.24	143	\$0.00	143
Generation	800510492 Interconnection Study	\$806.67	143	\$0.00	143
Generation	800510493 Interconnection Study	\$864.15	143	\$0.00	143
Generation	800510494 Interconnection Study	\$740.50	143	\$0.00	143
Generation	800510495 Interconnection Study	\$1,557.69	143	(\$500.00)	143
Generation	800510496 Interconnection Study	\$1,461.15	143	(\$4,440.00)	143
Generation	800510497 Interconnection Study	\$1,111.42	143	(\$1,450.00)	143
Generation	800510498 Interconnection Study	\$52.51	143	(\$1,250.00)	143
Generation	800510499 Interconnection Study	\$0.00	143	(\$1,500.00)	143
Generation	800510520 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510525 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510526 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510527 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510528 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510529 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510530 Interconnection Study	\$116.13	143	(\$1,400.00)	143
Generation	800510531 Interconnection Study	\$33.82	143	(\$1,400.00)	143
Generation	800510532 Interconnection Study	\$744.12	143	(\$3,140.00)	143
Generation	800510533 Interconnection Study	\$0.00	143	(\$1,600.00)	143
Generation	800510543 Interconnection Study	\$2,453.15	143	(\$2,340.00)	143
Generation	800510544 Interconnection Study	\$1,096.84	143	(\$19,120.00)	143
Generation	900196935 Interconnection Study	\$1,715.35	143	\$0.00	143
Generation	900196936 Interconnection Study	\$1,487.55	143	\$0.00	143
Generation	900196937 Interconnection Study	\$5,445.37	143	\$0.00	143
Generation	900196938 Interconnection Study	\$15,134.47	143	(\$50,000.00)	143
Generation	900197519 Interconnection Study	\$763.02	143	(\$1,215.20)	143
Generation	900197520 Interconnection Study	\$2,807.78	143	(\$14,000.00)	143
Generation	900197521 Interconnection Study	\$852.62	143	(\$1,250.00)	143
Generation	900197522 Interconnection Study	\$15,832.58	143	(\$22,500.00)	143
Generation	900197523 Interconnection Study	\$13,005.12	143	(\$10,000.00)	143
Generation	900197524 Interconnection Study	\$4,756.90	143	(\$22,500.00)	143
Generation	900197525 Interconnection Study	\$1,696.76	143	\$0.00	143
Generation	900197526 Interconnection Study	\$229.91	143	\$0.00	143
Generation	900197528 Interconnection Study	\$21,767.07	143	(\$30,000.00)	143
Generation	900197529 Interconnection Study	\$7,551.18	143	\$0.00	143
Generation	900197530 Interconnection Study	\$3,216.39	143	\$0.00	143
Generation	900197531 Interconnection Study	\$339.12	143	\$0.00	143
Generation	900197532 Interconnection Study	\$754.97	143	(\$2,139.33)	143
Generation	900197533 Interconnection Study	\$176.70	143	\$0.00	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Generation	900197534 Interconnection Study	\$176.70	143	\$0.00	143
Generation	900197535 Interconnection Study	\$342.26	143	\$0.00	143
Generation	900197536 Interconnection Study	\$1,987.93	143	(\$25,000.00)	143
Generation	900197537 Interconnection Study	\$0.00	143	(\$1,000.00)	143
Generation	900197538 Interconnection Study	\$561.79	143	(\$8,920.00)	143
Generation	900197559 Interconnection Study	\$0.00	143	(\$11,000.00)	143
Generation	900197560 Interconnection Study	\$4,408.79	143	\$0.00	143
Generation	900197561 Interconnection Study	\$1,786.61	143	(\$1,000.00)	143
Generation	900197562 Interconnection Study	\$1,780.92	143	(\$1,000.00)	143
Generation	900197563 Interconnection Study	\$1,442.90	143	(\$1,000.00)	143
Generation	900197564 Interconnection Study	\$1,983.56	143	(\$11,000.00)	143
Generation	900197565 Interconnection Study	\$567.76	143	\$0.00	143
Generation	900197738 Interconnection Study	\$0.00	143	(\$50,000.00)	143
Generation	900197759 Interconnection Study	\$10,245.44	143	(\$50,000.00)	143
Generation	900197760 Interconnection Study	\$661.62	143	\$0.00	143
Generation	900197761 Interconnection Study	\$79,274.61	143	\$0.00	143
Generation	900197762 Interconnection Study	\$79,897.06	143	\$0.00	143
Generation	900220661 Interconnection Study	\$78,712.37	143	\$0.00	143
Generation	900220662 Interconnection Study	\$80,972.92	143	\$0.00	143
Generation	900220663 Interconnection Study	\$79,512.11	143	\$0.00	143
Generation	900220666 Interconnection Study	\$79,346.56	143	\$0.00	143
Generation	900220667 Interconnection Study	\$78,937.68	143	\$0.00	143
Generation	900220669 Interconnection Study	\$82,199.88	143	\$0.00	143
Generation	900220670 Interconnection Study	\$82,085.78	143	\$0.00	143
Generation	900220672 Interconnection Study	\$79,576.24	143	\$0.00	143
Generation	900220673 Interconnection Study	\$79,237.32	143	\$0.00	143
Generation	900220675 Interconnection Study	\$79,755.01	143	\$0.00	143
Generation	900220677 Interconnection Study	\$81,144.43	143	\$0.00	143
Generation	900220678 Interconnection Study	\$80,916.08	143	\$0.00	143
Generation	900220679 Interconnection Study	\$79,501.12	143	\$0.00	143
Generation	900220680 Interconnection Study	\$923.91	143	\$0.00	143
Generation	900220681 Interconnection Study	\$80,309.58	143	\$0.00	143
Generation	900220682 Interconnection Study	\$78,422.63	143	\$0.00	143
Generation	900220683 Interconnection Study	\$78,422.63	143	\$0.00	143
Generation	900220684 Interconnection Study	\$78,507.17	143	\$0.00	143
Generation	900220685 Interconnection Study	\$79,963.79	143	\$0.00	143
Generation	900220686 Interconnection Study	\$78,507.17	143	\$0.00	143
Generation	900220687 Interconnection Study	\$78,507.17	143	\$0.00	143
Generation	900220688 Interconnection Study	\$79,944.53	143	\$0.00	143
Generation	900220689 Interconnection Study	\$79,545.03	143	\$0.00	143
Generation	900220690 Interconnection Study	\$79,691.81	143	\$0.00	143
Generation	900220691 Interconnection Study	\$85,856.93	143	\$0.00	143
Generation	900220692 Interconnection Study	\$79,849.77	143	\$0.00	143
Generation	900220693 Interconnection Study	\$78,528.71	143	\$0.00	143
Generation	900225714 Interconnection Study	\$80,026.29	143	\$0.00	143
Generation	900225715 Interconnection Study	\$92,616.87	143	\$0.00	143
Generation	900225716 Interconnection Study	\$78,528.75	143	\$0.00	143
Generation	900225717 Interconnection Study	\$78,888.15	143	\$0.00	143
Generation	900225718 Interconnection Study	\$79,703.67	143	\$0.00	143
Generation	900225799 Interconnection Study	\$82,032.79	143	\$0.00	143
Generation	900225800 Interconnection Study	\$3,379.20	143	(\$2,000.00)	143
Generation	900225801 Interconnection Study	\$194.46	143	(\$10,000.00)	143
Generation	900225802 Interconnection Study	\$3,725.35	143	\$0.00	143
Generation	900225803 Interconnection Study	\$5,836.08	143	(\$25,000.00)	143
Generation	900225804 Interconnection Study	\$14,634.36	143	(\$50,000.00)	143
Generation	900225805 Interconnection Study	\$7,840.86	143	(\$50,000.00)	143
Generation	900225806 Interconnection Study	\$9,741.24	143	(\$50,000.00)	143
Generation	900225807 Interconnection Study	\$5,612.73	143	(\$50,000.00)	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Generation	900225808 Interconnection Study	\$6,828.52	143	(\$50,000.00)	143
Generation	900225809 Interconnection Study	(\$2,286.52)	143	(\$25,000.00)	143
Generation	900225810 Interconnection Study	(\$2,507.02)	143	(\$25,000.00)	143
Generation	900225811 Interconnection Study	\$1,692.22	143	(\$9,000.00)	143
Generation	900225812 Interconnection Study	\$689.76	143	(\$1,000.00)	143
Generation	900232182 Interconnection Study	\$9,242.86	143	\$0.00	143
Generation	900232183 Interconnection Study	\$7,310.33	143	\$0.00	143
Generation	900232184 Interconnection Study	\$7,852.86	143	\$0.00	143
Generation	900232186 Interconnection Study	\$8,411.30	143	\$0.00	143
Generation	900232187 Interconnection Study	\$8,202.41	143	\$0.00	143
Generation	900232188 Interconnection Study	\$7,192.61	143	\$0.00	143
Generation	900232189 Interconnection Study	\$7,263.25	143	\$0.00	143
Generation	900232191 Interconnection Study	\$9,352.37	143	\$0.00	143
Generation	900232192 Interconnection Study	\$9,844.00	143	\$0.00	143
Generation	900232193 Interconnection Study	\$3,186.76	143	\$0.00	143
Generation	900232194 Interconnection Study	\$7,314.55	143	\$0.00	143
Generation	900232195 Interconnection Study	\$8,373.25	143	\$0.00	143
Generation	900232196 Interconnection Study	\$900.44	143	\$0.00	143
Generation	900232197 Interconnection Study	\$417.53	143	(\$5,000.00)	143
Generation	900232299 Interconnection Study	(\$2,060.91)	143	(\$25,000.00)	143
Generation	900232300 Interconnection Study	\$10,813.83	143	(\$22,500.00)	143
Generation	900232301 Interconnection Study	(\$1,518.46)	143	(\$11,000.00)	143
Generation	900232302 Interconnection Study	\$401.51	143	(\$1,300.00)	143
Generation	900232303 Interconnection Study	\$5,664.98	143	\$0.00	143
Generation	900232304 Interconnection Study	\$9,116.50	143	(\$60,000.00)	143
Generation	900232305 Interconnection Study	\$379.26	143	(\$1,320.00)	143
Generation	900232306 Interconnection Study	\$290.80	143	(\$1,320.00)	143
Generation	900232307 Interconnection Study	\$268.10	143	(\$1,320.00)	143
Generation	900232308 Interconnection Study	\$314.59	143	(\$1,160.00)	143
Generation	900232309 Interconnection Study	\$1,908.22	143	(\$10,000.00)	143
Generation	900232310 Interconnection Study	\$4,068.28	143	\$0.00	143
Generation	900232311 Interconnection Study	\$2,583.90	143	\$0.00	143
Generation	900232312 Interconnection Study	(\$10,834.94)	143	(\$80,000.00)	143
Generation	900232313 Interconnection Study	(\$3,763.20)	143	(\$24,000.00)	143
Generation	900232314 Interconnection Study	\$758.11	143	\$0.00	143
Generation	900232315 Interconnection Study	(\$1,059.83)	143	(\$11,000.00)	143
Generation	900232316 Interconnection Study	\$549.85	143	(\$1,500.00)	143
Generation	900232317 Interconnection Study	\$774.45	143	(\$1,500.00)	143
Generation	900232318 Interconnection Study	\$134.63	143	(\$1,500.00)	143
Generation	900232319 Interconnection Study	\$134.63	143	(\$1,500.00)	143
Generation	900232320 Interconnection Study	\$116.51	143	(\$1,500.00)	143
Generation	900232321 Interconnection Study	\$316.11	143	(\$1,500.00)	143
Generation	900232322 Interconnection Study	\$116.47	143	(\$1,500.00)	143
Generation	900232323 Interconnection Study	\$428.79	143	(\$1,500.00)	143
Generation	900232324 Interconnection Study	\$338.19	143	(\$1,500.00)	143
Generation	900232325 Interconnection Study	\$296.12	143	(\$1,500.00)	143
Generation	900232326 Interconnection Study	\$215.50	143	(\$1,500.00)	143
Generation	900232327 Interconnection Study	\$770.37	143	(\$3,500.00)	143
Generation	900232328 Interconnection Study	\$672.37	143	(\$1,500.00)	143
Generation	900232329 Interconnection Study	\$7,262.10	143	\$0.00	143
Generation	900232330 Interconnection Study	\$9,617.79	143	\$0.00	143
Generation	900232331 Interconnection Study	\$7,456.18	143	\$0.00	143
Generation	900232332 Interconnection Study	(\$36,512.42)	143	(\$285,000.00)	143
Generation	900232333 Interconnection Study	\$9,504.79	143	\$0.00	143
Generation	900232334 Interconnection Study	\$7,249.51	143	\$0.00	143
Generation	900232335 Interconnection Study	\$7,937.18	143	\$0.00	143
Generation	900232336 Interconnection Study	\$9,928.11	143	\$0.00	143
Generation	900232337 Interconnection Study	\$10,223.15	143	\$0.00	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA			

Generation	900232338 Interconnection Study	\$8,230.12	143	\$0.00	143
Generation	900242281 Interconnection Study	\$699.24	143	(\$1,500.00)	143
Generation	900242285 Interconnection Study	\$255.76	143	(\$1,500.00)	143
Generation	900242287 Interconnection Study	(\$962.84)	143	(\$11,000.00)	143
Generation	900242288 Interconnection Study	(\$1,156.96)	143	(\$11,000.00)	143
Generation	900242289 Interconnection Study	\$19.04	143	(\$3,500.00)	143
Generation	900242290 Interconnection Study	(\$434.64)	143	(\$11,000.00)	143
Generation	900242291 Interconnection Study	\$164.38	143	(\$3,500.00)	143
Generation	900242292 Interconnection Study	\$69.02	143	(\$3,500.00)	143
Generation	900242293 Interconnection Study	(\$25.60)	143	(\$3,500.00)	143
Generation	900242294 Interconnection Study	\$664.89	143	(\$3,500.00)	143
Generation	900242295 Interconnection Study	\$23.14	143	(\$3,500.00)	143
Generation	900242296 Interconnection Study	\$342.59	143	(\$3,500.00)	143
Generation	900242297 Interconnection Study	(\$1,104.59)	143	(\$11,000.00)	143
Generation	900242298 Interconnection Study	(\$1,228.50)	143	(\$11,000.00)	143
Generation	900242319 Interconnection Study	(\$303.71)	143	(\$3,500.00)	143
Generation	900242320 Interconnection Study	(\$1,479.71)	143	(\$11,000.00)	143
Generation	900242321 Interconnection Study	\$53.01	143	(\$3,500.00)	143
Generation	900242322 Interconnection Study	\$48.51	143	(\$3,500.00)	143
Generation	900242323 Interconnection Study	\$72.67	143	\$0.00	143
Generation	900242324 Interconnection Study	\$176.59	143	\$0.00	143
Generation	900242325 Interconnection Study	\$146.76	143	\$0.00	143
Generation	900242326 Interconnection Study	\$105.07	143	\$0.00	143
Generation	900242327 Interconnection Study	\$281.72	143	\$0.00	143
Generation	900242328 Interconnection Study	\$884.08	143	(\$1,500.00)	143
Generation	900242329 Interconnection Study	\$756.73	143	(\$1,500.00)	143
Generation	900242330 Interconnection Study	\$3,429.08	143	(\$1,500.00)	143
Generation	900242331 Interconnection Study	\$237.27	143	(\$3,500.00)	143
Generation	900242332 Interconnection Study	\$5,297.32	143	\$0.00	143
Generation	900242333 Interconnection Study	\$22,975.93	143	\$0.00	143
Generation	900242334 Interconnection Study	(\$327.43)	143	(\$6,000.00)	143
Generation	900242335 Interconnection Study	\$437.55	143	(\$6,000.00)	143
Generation	900242336 Interconnection Study	(\$235.58)	143	(\$13,000.00)	143
Generation	900242337 Interconnection Study	(\$1,112.36)	143	(\$11,000.00)	143
Generation	900242338 Interconnection Study	\$1,360.22	143	(\$3,300.00)	143
Generation	900242339 Interconnection Study	\$149.26	143	(\$3,300.00)	143
Generation	900242340 Interconnection Study	\$291.61	143	(\$1,420.00)	143
Generation	900242341 Interconnection Study	\$196.51	143	(\$5,500.00)	143
Generation	900242342 Interconnection Study	\$24.90	143	(\$5,140.00)	143
Generation	900242343 Interconnection Study	\$60.23	143	\$0.00	143
Generation	900242344 Interconnection Study	\$166.69	143	\$0.00	143
Generation	900268066 Interconnection Study	\$136.84	143	\$0.00	143
Generation	900268099 Interconnection Study	\$1,733.77	143	(\$5,759.00)	143
Generation	900268100 Interconnection Study	\$669.62	143	(\$8,500.00)	143
Generation	900268101 Interconnection Study	\$464.95	143	(\$6,000.00)	143
Generation	900268102 Interconnection Study	\$330.47	143	(\$11,000.00)	143
Generation	900268103 Interconnection Study	\$361.67	143	(\$22,000.00)	143
Generation	900268104 Interconnection Study	\$185.20	143	(\$7,000.00)	143
Generation	900268105 Interconnection Study	\$89.13	143	(\$8,500.00)	143
Generation	900268106 Interconnection Study	\$0.00	143	(\$11,000.00)	143
Generation	900268107 Interconnection Study	\$0.00	143	(\$2,500.00)	143
Generation	900268108 Interconnection Study	\$0.00	143	(\$2,500.00)	143
Generation	900268109 Interconnection Study	\$287.49	143	\$0.00	143
Generation	900268110 Interconnection Study	\$793.59	143	\$0.00	143
Generation	900268111 Interconnection Study	\$426.80	143	\$0.00	143
Generation	900268113 Interconnection Study	\$400.57	143	\$0.00	143
Generation	900268115 Interconnection Study	\$467.26	143	(\$6,000.00)	143
Generation	900268116 Interconnection Study	\$407.76	143	(\$1,000.00)	143

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Generation	900268117 Interconnection Study	\$224.18	143	\$0.00	143
Generation	900268118 Interconnection Study	\$4,844.72	143	\$0.00	143
Generation	900268124 Interconnection Study	\$1,027.16	143	(\$25,000.00)	143
Generation	900268125 Interconnection Study	\$467.06	143	(\$1,300.00)	143
Generation	900268126 Interconnection Study	\$410.02	143	(\$1,000.00)	143
Generation	900268127 Interconnection Study	\$591.17	143	(\$30,000.00)	143
Generation	900268128 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268131 Interconnection Study	\$0.00	143	(\$50,000.00)	143
Generation	900268132 Interconnection Study	\$91.41	143	(\$1,000.00)	143
Generation	900268139 Interconnection Study	\$118.92	143	(\$4,000.00)	143
Generation	900268140 Interconnection Study	\$9,747.27	143	(\$25,000.00)	143
Generation	900268141 Interconnection Study	\$132.89	143	\$0.00	143
Generation	900268144 Interconnection Study	\$433.74	143	(\$1,000.00)	143
Generation	900268145 Interconnection Study	\$27.51	143	(\$1,000.00)	143
Generation	900268146 Interconnection Study	\$170.30	143	(\$1,000.00)	143
Generation	900268147 Interconnection Study	\$476.73	143	(\$1,000.00)	143
Generation	900268150 Interconnection Study	\$0.00	143	(\$22,500.00)	143
Generation	900268151 Interconnection Study	\$598.01	143	(\$10,000.00)	143
Generation	900268152 Interconnection Study	\$786.70	143	(\$10,000.00)	143
Generation	900268153 Interconnection Study	\$454.47	143	(\$10,000.00)	143
Generation	900268154 Interconnection Study	\$218.28	143	(\$8,920.00)	143
Generation	900268155 Interconnection Study	\$289.58	143	(\$8,920.00)	143
Generation	900268156 Interconnection Study	\$218.28	143	(\$8,920.00)	143
Generation	900268157 Interconnection Study	\$218.28	143	(\$8,920.00)	143
Generation	900268158 Interconnection Study	\$313.36	143	(\$8,920.00)	143
Generation	900268159 Interconnection Study	\$327.55	143	\$0.00	143
Generation	900268160 Interconnection Study	\$1,197.93	143	\$0.00	143
Generation	900268161 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900268163 Interconnection Study	\$187.74	143	(\$3,279.81)	143
Generation	900268164 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268165 Interconnection Study	\$0.00	143	\$0.00	143
Generation	900268166 Interconnection Study	\$0.00	143	(\$22,500.00)	143
Generation	900268167 Interconnection Study	\$176.82	143	\$0.00	143
Generation	900268168 Interconnection Study	\$233.06	143	\$0.00	143
Generation	900268169 Interconnection Study	\$233.06	143	\$0.00	143
Generation	900268170 Interconnection Study	\$233.06	143	\$0.00	143
Generation	900268171 Interconnection Study	\$233.06	143	\$0.00	143
Generation	900268172 Interconnection Study	\$380.34	143	(\$30,000.00)	143
Generation	900268175 Interconnection Study	\$224.14	143	(\$10,000.00)	143
Generation	900268176 Interconnection Study	\$373.58	143	(\$10,000.00)	143
Generation	900268177 Interconnection Study	\$224.14	143	(\$10,000.00)	143
Generation	900268178 Interconnection Study	\$224.14	143	(\$10,000.00)	143
Generation	900268219 Interconnection Study	\$130.82	143	(\$5,000.00)	143
Generation	900268220 Interconnection Study	\$396.05	143	\$0.00	143
Generation	900268221 Interconnection Study	\$36,067.30	143	\$0.00	143
Generation	900268224 Interconnection Study	\$2,507.62	143	(\$10,000.00)	143
Generation	900268225 Interconnection Study	\$223.89	143	(\$1,000.00)	143
Generation	900268228 Interconnection Study	\$77.74	143	\$0.00	143
Generation	900268229 Interconnection Study	\$137.13	143	\$0.00	143
Generation	900268237 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268259 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268261 Interconnection Study	\$612.46	143	(\$25,000.00)	143
Generation	900268262 Interconnection Study	\$367.49	143	(\$25,000.00)	143
Generation	900268264 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268266 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900268267 Interconnection Study	\$1,153.27	143	(\$30,000.00)	143
Generation	900268268 Interconnection Study	\$1,084.21	143	(\$30,000.00)	143
Generation	900268269 Interconnection Study	\$0.00	143	(\$30,000.00)	143

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA

Generation	900268271 Interconnection Study	\$0.00	143	(\$3,500.00)	143
Generation	900268272 Interconnection Study	\$0.00	143	(\$3,500.00)	143
Generation	900268273 Interconnection Study	\$0.00	143	(\$3,500.00)	143
Generation	900268276 Interconnection Study	\$22.19	143	(\$60,000.00)	143
Generation	900268277 Interconnection Study	\$22.02	143	(\$60,000.00)	143
Generation	900344931 Interconnection Study	\$0.00	143	(\$30,000.00)	143
Generation	900344932 Interconnection Study	\$0.00	143	(\$30,000.00)	143
Generation	900344934 Interconnection Study	\$122.50	143	\$0.00	143
Generation	900344935 Interconnection Study	\$0.00	143	(\$5,000.00)	143
Generation	900344937 Interconnection Study	\$0.00	143	(\$2,500.00)	143
Generation	900344938 Interconnection Study	\$0.00	143	(\$25,000.00)	143
Generation	900346319 Interconnection Study	\$122.50	143	(\$1,300.00)	143
Generation	900346320 Interconnection Study	\$0.00	143	(\$50,000.00)	143
Generation	900346322 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900346323 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900346324 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900346325 Interconnection Study	\$19.44	143	(\$25,000.00)	143
Generation	900363110 Interconnection Study	\$19.44	143	(\$25,000.00)	143
Generation	900363111 Interconnection Study	\$19.44	143	(\$25,000.00)	143
Generation	900363112 Interconnection Study	\$19.44	143	(\$25,000.00)	143
Generation	900363113 Interconnection Study	\$0.00	143	(\$4,000.00)	143
Generation	900363114 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900363115 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900363116 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900363117 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900363118 Interconnection Study	\$0.00	143	(\$10,000.00)	143
Generation	900363280 Interconnection Study	\$0.00	143	(\$1,367.34)	143
Generation	900363281 Interconnection Study	\$0.00	143	(\$1,458.76)	143
		\$6,591,195.17		(\$5,843,587.27)	

Schedule Page: 231 Line No.: 22 Column: b

Column B may NOT include A and G expenses for the entire period.

Schedule Page: 231 Line No.: 22 Column: d

Column D includes refunds that were paid to the interconnection customer in 2010 resulting from payments received exceeding actual study costs and includes interest payments on refunds. multiple orders for the same project may net to actual payment/disbursements to customers.

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Income Tax-Related Deferred Charges	1,561,098,587	1,086,052,362	Various	791,801,495	1,855,349,454
2	FASB 109 gross-up of taxes.					
3						
4						
5	Unamortized Cost - Palo Verde Commercial	449,076		406	27,922	421,154
6	Operating Date Adjustment					
7	To recover costs incurred between FERC and					
8	CPUC commercial operating date.					
9	(Amortization Period: 03/1988-01/2026)					
10						
11						
12	Health and Safety Rewards	13,000,000		182	13,000,000	
13	To reflect accrued rewards related to health					
14	and safety, number of circuit interruptions, and					
15	customer satisfaction.					
16						
17						
18	Exchange Energy	758,729	5,586,251	407	3,771,632	2,573,348
19	To record non-cash related energy costs not					
20	involving the transfer of cash between SCE and					
21	third parties.					
22						
23						
24	Decommissioning Not Yet Collected in		138,270,833	Various	138,270,833	
25	Rates San Onofre 1 - Long Term					
26	To recover remaining decommissioning costs on					
27	unit shut down in 1992.					
28						
29						
30	Palo Verde Units 2 & 3	1,805,744		406	112,274	1,693,470
31	To recover deferred common facilities charges.					
32	(Amortization Period: 09/1986 - 01/2026)					
33						
34						
35	Catastrophic Event Memorandum Account	34,945,900	10,453,324	Various	23,986,246	21,412,978
36	To record costs incurred by SCE associated					
37	with a catastrophic event for restoring					
38	utility service to customers; repairing, replacing,					
39	or restoring damaged utility facilities; and					
40	complying with governmental agency orders.					
41						
42						
43						
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Environmental Clean-up Costs	46,555,481	35,454,111	Various	14,751,835	67,257,757
2	To recover ratepayer's portion of environmental					
3	costs.					
4						
5						
6	Nuclear Fuel CC Fuel Stock-SONGS/Palo Verde	1,557,561	2,193,929	Various	3,751,490	
7	Reg. asset for nuclear fuel carrying costs.					
8						
9	San Onofre Nuclear Generating Station	1,303,696		406	103,484	1,200,212
10	To recover deferred common facilities charges					
11	incurred between FERC and CPUC commercial					
12	operating date.					
13	(Amortization Period: 10/1982-07/2022)					
14						
15	Hazardous Waste Balancing Account	2,153,160	8,951,590	Various	2,491,860	8,612,890
16	To recover collaborative hazardous waste costs.					
17						
18	Post Employment Benefit Accrual	96,230,319	5,146,598			101,376,917
19	To reflect a regulatory asset for future recovery					
20	of post employment benefits associated with					
21	SFAS 112.					
22						
23	Environmental Remediation	30,389,600	5,879,860	253	9,855,389	26,414,071
24	To recover 90% of estimated future environmental					
25	remediation/cleanup costs.					
26						
27	Unamortized Steam Plant	40,682,527		108	6,617,062	34,065,465
28	To reflect Mohave Generating Station Plant as a					
29	regulatory asset.					
30	(Amortization Period: 01/2006-06/2016)					
31						
32						
33	CARE Balancing Account	56,740,500	55,709,329	Various	57,236,754	55,213,075
34	To reflect in rates, through application of the					
35	Public Purpose Program Charge the costs assoc-					
36	iated with the CARE Program as authorized in					
37	various CPUC Decisions.					
38						
39						
40	Unamortized Nuclear Plant	169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
41	To reflect SONGS and Palo Verde Nuclear	169,953,145	8,225,096,795	108	8,251,334,713	143,715,227
42	Plants as regulatory assets.					
43	(Amortization Period: 03/1988-01/2016)					
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Nuclear & Coal Asset Retirement Obligation (ARO)	260,799,012	471,238,095	Various	576,507,066	155,530,041
2	To establish a regulatory asset for decommission-					
3	ing costs collected in rates for Nuclear and coal					
4	ARO property (Amort. Period: 12/2003-12/2025)					
5						
6						
7	Reliability Service (RS) Balancing Account	275,644	5,223,346	Various	1,308,276	4,190,714
8	To track the RS revenues and RS costs to ensure					
9	that SCE neither over-collects nor under-collects					
10	RS costs assessed.					
11						
12	PBR And Other Related Ratemaking	(15,788,038)	17,167,011	Various	8,626,105	-7,247,132
13	Reclassification of PBR incentive and other					
14	ratemaking amounts to a contra-asset account.					
15						
16						
17	Bilateral Energy & Gas Financial Instruments-	17,588,712	172,060,877		34,505,869	155,143,720
18	Short Term					
19	To record the mark-to-market adjustments related					
20	to the short term financial instruments used to					
21	hedge power purchases and natural gas costs					
22	for tolling.					
23						
24						
25	Bilateral Energy & Gas Financial Instruments-	308,478,457	849,919,716		1,023,113,759	135,284,414
26	Long Term					
27	To record the mark-to-market adjustments related					
28	to the long term financial instruments used to					
29	hedge power purchases and natural gas costs for					
30	tolling.					
31						
32	Pension Costs Balancing Account	25,318,612	19,068,443	Various	28,272,604	16,114,451
33	To record the difference between pension costs					
34	authorized by the Commission, and recorded					
35	pension expenses.					
36						
37	Post Employment Benefits Other than Pensions (PBOP)	9,274,171	(1) 254		9,274,170	
38	Costs Balancing Account					
39	To record the difference between PBOP costs					
40	authorized by the Commission, and recorded PBOP					
41	expenses.					
42						
43	Mohave Balancing Account		6,801,908	Various	4,594,733	2,207,175
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	To track the difference between: (1) recorded					
2	capital-related expenses, operating expenses and					
3	worker protection expenses associated with the					
4	Mohave Generating Station, and (2) the authorized					
5	Mohave revenue requirement as adopted in					
6	D.09-03-025					
7						
8	Regulatory Asset Pension - SFAS 158	1,014,297,001	146,606,000	228	62,732,000	1,098,171,001
9	To reflect regulatory asset resulting from the					
10	adoption of SFAS 158-Employers' Accounting					
11	for Defined Benefit Pension & Other Postretirement					
12	Plans.					
13						
14	Project Development Division Memorandum Account	7,835,113	4,133,804	Various	3,926,670	8,042,247
15	To track the Project Development Division recorded					
16	support costs, as authorized in CPUC D.06-05-016.					
17						
18						
19	Leases for Power Contracts	56,648,809	1,021,619	Various	8,780,737	48,889,691
20	To record regulatory asset associated with power					
21	contracts that are subject to lease accounting					
22	rules under the guidance of EITF No. 01-8 and					
23	SFAS 13.					
24	(Amortization Period: 12/2006 - 12/2016)					
25						
26						
27	Nuclear Decommissioning Adjustment Mechanism	61,202	7,489,317	Various	7,550,519	
28	To record NDAM revenue, authorized and recorded					
29	costs related to the decommissioning of San Onofre					
30	Nuclear Generating Station and Palo Verde Nuclear					
31	Generating Station.					
32						
33	Gross Revenue Sharing Mechanism		3,374,844	Various	3,374,844	
34	To record the customers' share of certain Other					
35	Operating Revenue (OOR), as per Advice Letter					
36	No. 1413-E-A, dated September 16, 1999.					
37						
38						
39	Undistributed Expense Regulatory Asset	635,055	929,762	407	810,822	753,995
40	To record a regulatory asset associated with the					
41	accrual of various undistributed expenses.					
42						
43						
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Dept of Energy Litigation Memorandum Acct.	498,288	15,115	Various	108,603	404,800
2	To record SCE's incremental litigation costs and					
3	damages and other proceeds received by SCE from					
4	the federal government associated with the breach					
5	of contract complaint brought against the DOE for					
6	failure to take possession of San Onofre Nuclear					
7	Generating Station spent fuel.					
8						
9						
10	Results Sharing Memorandum Account (RSMA)	316,534	3,047,285	Various	3,363,819	
11	To track the difference between authorized and					
12	recorded Results Sharing expenses paid out.					
13						
14						
15	Market Redesign and Technology Upgrade Memorandum	8,530,513	22,391,533	Various	2,523,265	28,398,781
16	Account (MRTUMA)					
17	To record SCE's incremental costs associated with					
18	the CAISO's MRTU initiative.					
19						
20						
21	Misc. Balancing Account Activity	1,523,466	166,862	Various	930,328	760,000
22	To capture various accrued purchased power					
23	agreements and other miscellaneous regulatory					
24	liabilities.					
25						
26						
27	Solar Photovoltaic Program Memo Account	2,867,538	6,435			2,873,973
28	To record incremental O&M and capital related					
29	revenue requirement associated with the first \$25					
30	million of direct capital expenditures incurred in					
31	the Solar PV Program.					
32						
33						
34	Long-Term Procurement Technical Assist MA	198,912	31,271	254	198,912	31,271
35	To record the technical assistance costs incurred					
36	by the Commission and paid by SCE in connection					
37	with the implementation and administration of the					
38	Long-Term Procurement Plan (LTPP).					
39						
40	Non-discretionary Service Cost MA LT	26,528	63,814	407	19,688	70,654
41	To record SCE's incremental costs incurred for					
42	providing non-discretionary services in accordance					
43	with Ordering Paragraph 9 or D.08-05-003.					
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	New System Gen Balancing Account	41,754,652	16,986,439	407	17,971,017	40,770,074
2	To record the benefits and costs of Power Purchase					
3	Agreements (PPAs) and SCE owned peaker					
4	generation unit associated with new generation					
5	resources pursuant to D.07-09-044, D06-07-029					
6	and D09-03-031.					
7						
8	Medical Balancing Account	6,607,345	5,607,410	Various	12,214,755	
9	To record the difference between the authorized and					
10	and recorded Medical, Dental, Vision expenses in					
11	accordance with D.09-03-025.					
12						
13	Four Corners Capital	832,893	871,249			1,704,142
14	To track the revenue requirement associated with					
15	the GRC forecast of Four Corners Capital Expend-					
16	iture that may become subject to the Emission					
17	Performance Standards (EPS) that were effective					
18	January 25, 2007, pursuant to a decision in					
19	R.06-04-009.					
20						
21						
22	CWIP Balancing Account	5,215,905	10,736,619	Various	5,418,184	10,534,340
23	Tracks Construction Work in Progress revenue					
24	requirement and revenues applicable to retail, end					
25	use transmission customers on a monthly basis					
26	to ensure that the Participating TO neither over-					
27	collects nor undercollects CWIP revenue.					
28						
29						
30	Clean Technology Generation Balancing Account	591,599		254	591,599	
31	To record up to \$4.6 million related to the carbon					
32	sequestration evaluation costs per D. 08-04-038.					
33						
34						
35	Purchase Agreement Administrative Costs	189,198		254	189,198	
36	Balancing Account					
37	To record the difference between SCE's actual and					
38	authorized administrative costs associated with					
39	four (4) third-party demand response contracts					
40	during the period March 13, 2008 through December					
41	31, 2012 in accordance with D. 08-03-017.					
42						
43						
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Fire Hazard Prevention Memorandum Account	978,942	11,669,172			12,648,114
2	To record costs incurred related to fire hazard					
3	prevention in compliance with Commission Decision					
4	D. 09-08-029.					
5						
6						
7	Renewable Portfolio Standard Costs Memorandum	187,837	400,887			588,724
8	Account					
9	To record the (1) costs of studies of inter-					
10	connection facilities and network transmission up					
11	grades necessary to interconnect RPS generation					
12	resources contracted in the 2003 and 2005 RPS					
13	solicitations and additional resources to be					
14	contracted in the future in accordance with					
15	ordering Paragraph No 1 of Resolution E-3969; (2)					
16	costs of studies associated with the Tehachapi					
17	Wind Resource Area, in accordance with Ordering					
18	Paragraph No. 2 of Resolution E-3969; and (3)					
19	payments allocated to SCE for contractor(s) hired					
20	by Exeuctive Director of the Commission to provide					
21	technical and other support to Commission Staff in					
22	the advancement of RPS goals, pursuant to					
23	Ordering Paragraph 8 of D.06-10-050.					
24						
25						
26	Hydrogen Energy California Memorandum Account	13,520,878	3,502,036	Various	17,022,914	
27	To record up to \$30 million of costs related to the					
28	developement of an intergrated gasification					
29	combined cycle (IGCC) facility with carbon capture					
30	for use in Enhanced Oil Recovery (EOR) with					
31	sequestration.					
32						
33						
34						
35	FAS 87 Pen Reg Asset	24,068,000	52,721,000			76,789,000
36	To record the cumulative difference between pension					
37	expense calculated for ratemaking purposes and the					
38	amount calculated for accounting purposes since					
39	implementation of SFAS 87 in 1987. The over-					
40	collected balance results from the ratemaking					
41	calculation exceeding the accounting calculation					
42	during this period of time.					
43						
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Palo Verde Balancing Account		14,155,056	Various	14,155,056	
2	To record the difference between the authorized and					
3	SCE's actual Operations and Maintenance (O&M),					
4	Administrative & General (A&G), Pension & Benefits					
5	(P&B), Payroll Taxes and oversight expenses.					
6						
7	Public Purpose Programs Adjustment Mechanism		155,245,928	Various	48,032,097	107,213,831
8	To record Public Good Charge Revenue, PGC expenses					
9	authorized in P. U. Code Section 399.8, and other					
10	CPUC Public Purpose Program revenues and expenses.					
11						
12	Residential Energy Disconnect Memorandum Account		35,223			35,223
13	To track any significant additional costs,					
14	operations and maintenance charges and					
15	uncollectables that are in excess of those					
16	projected in the utilities last GRC in improving					
17	customer notification and education regarding					
18	service disconnections due to nonpayment.					
19						
20	Mohave Benefits Regulatory Account	437,899				437,899
21	To record the regulatory asset associated with the					
22	education reimbursement, outplacement and extended					
23	health care benefits for Mohave employees.					
24						
25	GCAC Balancing Account		64,335			64,335
26	Balance composed of Gas Costs Adjustment Clause					
27	which recovers/refunds gas costs on Catalina Island					
28						
29	Smart Grid American Recovery and Reinvestment Act		357,710			357,710
30	Memorandum Account					
31	To record SCE's incremental O&M expenses, incre-					
32	mental capital-related revenue requirements, and					
33	DOE funding consistent with Order Paragraph 2 of					
34	decision (D.) 09-09-029.					
35						
36	Unamortized Legacy Meters - Net		104,903,349			104,903,349
37	(Expected to be recovered by 2025)					
38						
39						
40						
41						
42						
43						
44	TOTAL	4,021,347,846	19,911,905,246		19,464,565,311	4,468,687,781

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 232.1 Line No.: 40 Column: b

Due to FERC system restrictions, had to split amounts in half in order to reflect amounts correctly.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227
339,906,289	16,450,193,590		16,502,669,426	287,430,453

Schedule Page: 232.1 Line No.: 40 Column: c

Due to FERC system restrictions, amounts have been split in half in order to correctly reflect balances.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227
339,906,289	16,450,193,590		16,502,669,426	287,430,453

Schedule Page: 232.1 Line No.: 40 Column: e

Due to FERC system restrictions, amounts have been split in half in order to correctly reflect balances.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

339,906,289	16,450,193,590		16,502,669,426	287,430,453
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Schedule Page: 232.1 Line No.: 41 Column: b

Due to FERC system restrictions, amounts have been split in half in order to correctly reflect balances.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227
339,906,289	16,450,193,590		16,502,669,426	287,430,453

Schedule Page: 232.1 Line No.: 41 Column: c

Due to FERC system restrictions, amounts have been split in half in order to correctly reflect balances.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227
339,906,289	16,450,193,590		16,502,669,426	287,430,453

Schedule Page: 232.1 Line No.: 41 Column: e

Due to FERC system restrictions, amounts have been split in half in order to correctly reflect balances.

Balance at beginning of year	Debits	Account Charged	Amount	Balance as of Dec 31, 2010
(b)	(c)	(d)	(e)	(f)
339,906,289	16,450,193,590	108	16,502,669,426	287,430,453
169,953,144	8,225,096,795	108	8,251,334,713	143,715,226
169,953,145	8,225,096,795	108	8,251,334,713	143,715,227

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			

FOOTNOTE DATA

339,906,289	16,450,193,590		16,502,669,426	287,430,453
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Prepaid Software License	4,112,021	1,575,215	Various	1,859,068	3,828,168
2	WIP - Dry Cask		1,493,539	Various	1,440,300	53,239
3	OWIP - ECS Def Debit	4,354,113	12,286,936	Various	9,936,623	6,704,426
4	Prelim. Engineering Costs	72,880	1,004,049	Various	110,523	966,406
5	Misc. Deferred Debits	10,206,154	7,842,675	Various	14,344,937	3,703,892
6	CSBU DSGN Eng Def Exp	-27,358	5,003,771	Various	4,788,732	187,681
7	CSBU DWR Admin Fees	-3,697	19,457	Various	21,499	-5,739
8	Plant Claims Pending	17,818,275	501,509	Various	2,905,417	15,414,367
9	Def Deb - Vent Surch	2,391,439	140,731	Various	2,343	2,529,827
10	SLU Def Proj COst		11,727	Various	200,983	-189,256
11	Right to PP-WAPA	18,640,000		228	2,070,000	16,570,000
12	Def Prpd Pension Costs	92,183,958	10,525,885	926	149,843	102,560,000
13	A/R - New Slr Hms PrtnrPrgrm LT	-145,065	17,161	143	171,605	-299,509
14						
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46						
47	Misc. Work in Progress	66,165,198				69,618,144
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	215,767,918				221,641,646

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 13 Column: a
A/R - New Solar Homes Partnership Program LT

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 Beginning of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Footnote	1,325,545,098	1,269,250,820
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,325,545,098	1,269,250,820
9	Gas		
10	See Footnote	-342,796,107	-444,433,378
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15)	-342,796,107	-444,433,378
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	982,748,991	824,817,442

Notes

Notes

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

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

Account Sub- Division	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
190.010	Amort of Debt Issuance Cost	438,596.93	485,773.94
190.100	ECAC	28,484.05	28,484.05
190.106	Franchise Requirements	3,679.67	3,679.67
190.107	Relicensing Fees	(6,876,144.09)	(6,876,144.09)
190.108	AC Def Inc Tax - Exchg Energy	(308,574.89)	(1,046,580.71)
190.110	AC Def Inc Tax - ECAC Incent	0.00	(30,591.00)
190.111	Yuma Axis Generating Stn	(1,905,780.24)	(1,905,780.24)
190.112	Toxic Substance Settlemt	0.00	0.00
190.113	Executive Incentive Comp	4,782,074.50	4,782,074.50
190.124	AC Def Inc Tax - TCF PV3 Ovrroll 03	1,598,977.03	(43,388,808.08)
190.125	Unbilled Revenue	0.31	0.31
190.130	Acc charges	2,155,510.00	2,155,510.00
190.131	DIT - APS Right of Way	7,209,069.41	12,201,001.77
190.132	Corp Name Change	13,776.84	13,776.84
190.144	QF termination payments	124,640.75	0.75
190.145	Mescalero Fuel Storage	(88,901.37)	(88,901.37)
190.146	San Antonio Trust	0.00	0.00
190.148	Photovoltaic Facilities	(93,674.81)	(93,674.81)
190.190	Uncollectible Accts. Exp.	(480,607.96)	(480,607.96)
190.191	CCFT - TSB -FAS 109	565,837.30	565,837.30
190.208	RAR Rollforward	1,522,503.00	1,522,503.00
190.210	Prepaid Expenses	(4,768,279.78)	(4,768,279.78)
190.216	Bond Discount Amort	1,595,900.35	2,294,851.36
190.220	CCFT - Electric	97,753,465.68	24,245,612.43
190.222	Decomm Net Earn - Non Qua	91,466,389.29	91,012,714.99
190.224	Def Tax Flow Thru ITC	43,143,708.31	38,320,163.40
190.225	Def Tax ITC 2-Yr Average	935,905.13	935,731.00
190.232	Executive Incentive Plan	4,483,689.98	6,848,033.55
190.234	Pension Reserve	121,055,325.19	122,076,150.12
190.237	Restricted Stock	0.00	0.00
190.240	Uncollectible Accounts E	17,970,356.62	29,208,568.64
190.241	Coolwater - CPUC	0.00	0.00
190.242	Exec Retrmnt Provision - FAS109	(28,216,074.53)	(28,216,074.53)
190.243	CRE Lease Options	0.00	0.00
190.244	ARAM	9,001,569.63	7,934,736.25
190.248	Ins - Inj/Damages Prov	90,644,789.86	89,080,416.09
190.253	Misc Def Tax	(10,109,858.15)	(10,109,858.15)
190.254	Unrealized Gain - Decomm	315,183,619.36	389,309,625.31
190.255	Hazardous Waste	30,204.00	30,204.00
190.256	Accrued Vacation	24,563,047.95	25,874,022.93
190.258	Health Care - IBNR	1,033,600.39	1,033,600.39
190.266	Uncollec Accts-Claims	3,359,930.64	3,793,860.97
190.297	Def Tax - CCFT Base Rates - R.L.	25,786,446.99	29,118,466.99
190.319	Ins Res/Casualty Loss	49,878.37	49,878.37
190.350	DOC ER88-83	24,169,874.68	29,400,616.59
190.351	FERC Res Misc	0.00	0.00
190.365	Decomm NQ Expenses	81,564,942.07	82,056,910.18
190.368	FERC ER 85-67	0.00	0.00
190.393	DIT - SFAS 158 - Short Term	8,299,526.90	9,469,196.10
190.407	GRC Marine Mitigation	2,210,064.01	2,210,064.01
190.417	DIT on Late Pymt Bal Acct.	0.00	0.00
190.419	Air Conditiong Cycling Program Mech. Acct. (ACCPMA)	0.00	0.00
190.426	Def Tax - Prov For Basln Bal. Acct.	0.00	0.00
190.431	Nuc Decomm Adj Mech (NDAM)	333,518.15	358,409.06
190.433	Pub Purp Prg Adj Mech (PPPAM)	0.00	(43,603,864.60)
190.434	Family Energy Rate Assistance Bal. Acct. (FERABA)	0.00	0.00
190.435	Elect Dist Rev Adj Bal (EDRABA)	0.00	0.00
190.436	Energy Resource Recov (ERRA)	0.00	0.00
190.444	DIT - SRPIM	840,071.13	840,071.13

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

190.445	DIT WECC Statutory Costs	0.00	(11,548.72)
190.448	Base Revenue Requirement	43,138,587.64	43,138,587.64
190.457	Demand Responsiveness Memo	13,075,175.44	13,075,175.44
190.459	DIT - FIN Reporting Reserves	19,902,008.16	20,394,017.18
190.463	DIT Demand Respon Prg Bal Acct	0.00	0.00
190.485	DIT Energy Assistant Fund	0.00	0.00
190.510	Nuclear Fuel	(62,638,293.47)	(65,593,674.33)
190.520	NQ Decom. Withdraws	(113,809,286.44)	(114,025,125.73)
190.561	R&D Overcollection	(88,582.28)	(88,582.28)
190.640	DSMAC Expenses	(2,029,416.47)	(2,029,416.47)
190.700	Conserv Hardware Rebate	0.00	0.00
190.738	Cont in Aid of Const	(11,061,691.66)	(6,713,456.70)
190.745	Int Capitalized - AFUDC	151,341,274.04	171,475,070.32
190.746	Contra-Int Capitalized	0.00	0.00
190.748	ITCC - CIAC - State	263,335,633.45	284,574,699.25
190.800	PBOP 401H Amortization	92,239,342.27	53,948,186.58
190.910	Fixed Costs	7,488,825.20	5,770,278.64
190.925	LSFO Differential	(1,639,702.62)	0.38
190.926	DFO Differential	20,808.24	68,487.10
190.961	ADIT - Environ Remed	(168,753.95)	(168,753.95)
	DIT DSM-ENERGY EFFICIENCY	(18,693,383.51)	(18,693,383.51)
	DIT DSM-LOW INCOME	2,278,921.49	2,278,921.49
	DIT FIRM TRANSMISSION RIGHTS BA	1,271,191.41	458,781.00
	SOLAR INVESTMENT TAX CREDIT	3,474,092.11	21,249,436.47
	MISC_Year 2009	62,914.05	(138,961.92)
	Marine Mitigation	(1,994,965.00)	(1,994,965.00)
	DIT MISC Reg Liab/Asset	13,251,947.48	13,251,947.48
	Rollforward of settled audit ATL RB-Fed	(155,622,250.35)	0.00
	Rollforward of settled audit ATL RB-State	(421,939.08)	0.00
	MRTUMA	(3,469,359.70)	(11,549,784.55)
	FHPMA LT	(398,135.96)	(5,114,869.25)
	FC Cpital LT	(338,737.54)	(722,193.27)
	DIT Renewable Portfolio STD Costs MA	(76,393.42)	(239,434.02)
	Def Tax_Reclass Federal GS Regulatory Impact	155,622,250.35	0.00
	Def Tax_Reclass Federal GS Regulatory Impact	421,939.08	0.00
	Total Electric	1,325,545,097.61	1,269,250,819.94

Schedule Page: 234 Line No.: 10 Column: a

GAS AND OTHER INCOME:

Account Sub- Division	Description	Balance at Beginning of Year	Balance at End of Year
190.125	Unbilled Revenue	0.00	0.00
190.180	DIT - RAR Rollforward - State	173,793,854.58	116,201,673.11
190.181	DIT - RAR Rollforward - Federal	(519,082,609.13)	(507,149,558.39)
190.208	RAR Rollforward	0.00	0.00
190.212	Ad Val Lien Date-Other	(559,168.97)	(344,000.63)
190.217	CCFT - Gas	(12,037.88)	(12,036.00)
190.218	CCFT - Other	(5,100,150.62)	(5,100,150.62)
190.219	CCFT - Water	(9,057.53)	(9,042.00)
190.231	Def Tax - Etiwanda Wst Wtr	27,293.66	15,972.04
190.501	ACRS SONGS PV Write-off	0.00	0.00
190.910	Book Reserve	0.00	0.00
190.912	Misc FPO --- ULD adjustment of 0.26	0.26	0.00
	Rollforward Orig Issue State 09 May Filing	22,718,793.00	23,554,610.00
	Rollforward of settled audit ATL NONRB-Fed	(2,713,759.87)	(1,687,552.87)
	Rollforward of settled audit ATL NONRB-State	(11,859,263.92)	(67,327,155.38)
			(14,325.09)
			0.12
			(329,490.86)
			(2,232,321.80)
	Total Gas and Other Income	(342,796,106.42)	(444,433,378.37)

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	Account 201			
2	Common Stock, no par value	560,000,000		
3	TOTAL_COM	560,000,000		
4				
5	Account 204			
6	Preferred stock - without			
7	Mandatory Redemption Requirements			
8	Cumulative participating, not redeemable			
9				
10	Cumulative Preferred:	24,000,000		
11	4.08% Series		25.00	25.50
12	4.24% Series		25.00	25.80
13	4.32% Series		25.00	28.75
14	4.78% Series		25.00	25.80
15				
16				
17				
18	Preferred Stock - with Mandatory Redemption			
19	Requirements			
20	\$100 Cumulative Preferred:	12,000,000	100.00	
21				
22				
23	Preference Stock			
24	No Par Value			
25	Non-Voting and Non-Cumulative	50,000,000		
26				
27	5.349% SERIES A			100.00
28	6.125% SERIES B			100.00
29	6.000% SERIES C			100.00
30				
31	TOTAL_PRE	86,000,000		
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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.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
434,888,104	2,168,054,319					2
434,888,104	2,168,054,319					3
						4
						5
						6
						7
						8
						9
						10
650,000	16,250,000					11
1,200,000	30,000,000					12
1,653,429	41,335,725					13
1,296,769	32,419,225					14
						15
						16
						17
						18
						19
						20
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						22
						23
						24
						25
						26
4,000,000	400,000,000					27
2,000,000	200,000,000					28
2,000,000	200,000,000					29
						30
12,800,198	920,004,950					31
						32
						33
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						41
						42

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

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

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Accounts 208, 209 and 210	
2	None	
3		
4	Miscellaneous Paid-in Capital (Account 211)	
5		
6	Respondent issued 778,150 shares of Common Stock in the form of	
7	a 4% stock dividend to the holders of Original Preferred and	
8	Common Stock on January 5, 1961.	
9		
10	778,150 X 32.875 \$25,581,681.25 (Market Value)	
11	778,150 X 12.500 9,726,875.00 (Account 201)	15,854,806
12		
13	Respondent recorded this amount (\$51,497) as a result of merging	
14	with California Electric Power Co., which in turn had recorded it	
15	in connection with the acquisition of a subsidiary company in 1948.	51,497
16		
17	Respondent issued 7,220,000 shares of Common Stock and 296,769	
18	shares of 4.78% Cumulative Preferred Stock to the respective	
19	holders on December 31, 1963, of California Electric Power Co.	
20	Common and \$3 Cumulative Preferred Stock.	
21		
22	Common Stock:	
23	Acquired Book Value - \$37,570,757.06	
24	Account 201 (7,220,000 X 4 -1/6) = 30,083,333.33	7,487,424
25		
26		
27	4.78% Cumulative Preferred Stock:	
28	Acquired Book Value - \$4,946,150.00	
29	Account 201 (296,769 X \$25.00) = 7,419,225.00	-2,473,075
30		
31		
32	Miscellaneous Paid-in Capital (Account 211) Continued:	
33		
34	Return of money deposited in Trust Fund for redemption of	
35	Cumulative Preferred Stock - 4.88% Series.	10,445
36		
37		
38		
39		
40	TOTAL	585,772,712

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of 2010/Q4
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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	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Respondent recorded this amount as a result of the conversion	
4	of 12-1/2% convertible subordinated debentures, due 1997.	
5	Amount represents interest foregone by debenture holders	
6	from the interest payment date to the conversion dates.	921,446
7		
8	Issuance of 10,000 shares of Edison International Common Stock under	
9	Edison's 1987 Long-term Incentive Compensation Plan. (1988)	317,500
10		
11	Issuance of 12,500 shares of Edison International Common Stock under	
12	Edison's 1987 Long-term Incentive Compensation Plan. (1989)	492,188
13		
14	Accrued dividend equivalents in connection with the exercise	
15	of stock options to purchase 1,600 shares of Edison International Com-	
16	mon Stock under Edison's 1987 Long-term Incentive Compensation	
17	Plan. (1991)	11,392
18		
19	Edison International capital contribution (1992)	184,500,000
20		
21	Issuance of 1,600 shares of Edison International Common Stock under	
22	Edison's 1992 Directors Incentive Compensation Plan. (1992)	64,228
23		
24	Issuance of 4,935 shares of Edison International Common Stock by	
25	exercising stock options under Edison's 1987 Long-term	
26	Incentive Compensation Plan. (1992)	29,911
27		
28	Difference in market price and option price for stock	
29	option exercise on 12-22-95 under Executive Long-Term	
30	Incentive Plan. (1995)	7,616
31		
32	Transferred to Common Stock Account 201 as a result of	
33	stock split effective June 1, 1993.	-25,230,392
34		
35	Miscellaneous Paid-in-Capital (Account 211) Continued:	
36		
37	Stock Options Exercised (1998)	600,289
38		
39	Edison International Capital Contribution (1998)	153,000,000
40	TOTAL	585,772,712

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	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Performance Shares (2001)	2,473,341
4		
5	Performance Shares (2002)	4,203,885
6		
7	Performance Shares (2003)	-3,806,452
8		
9	Performance Shares (2004)	12,273,434
10		
11	Performance Shares (2005)	20,536,431
12		
13	Stock-Based Compensation (2006)	8,157,333
14		
15	Excess Tax Benefits Related to Stock Based Awards (2006)	17,087,817
16		
17	Reclassification of Shares Purchased for Stock Based Compensation	78,102,459
18	(2002-2006)	
19		
20	Stock Based Compensation (2007)	17,949,511
21		
22	Excess Tax Benefits Related to Stock Based Awards (2007)	28,476,623
23		
24	Stock Based Compensation (2008)	18,468,441
25		
26	Excess Tax Benefits Related to Stock Based Awards (2008)	4,136,174
27		
28	Gain on Reacquired Preferred Stock (2008)	1,746,500
29		
30	Stock Based Compensation (2009)	12,969,153
31		
32	Excess Tax Benefits Related to Stock Based Awards (2009)	6,670,516
33		
34	Stock Based Compensation (2010)	17,123,627
35		
36	Excess Tax Benefits Related to Stock Based Awards (2010)	3,558,644
37		
38		
39		
40	TOTAL	585,772,712

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	Common Stock	103,156
2		
3	Preferred Stock	1,709,919
4		
5		
6		
7		
8		
9	Preference Stock	
10	5.349% SERIES A	5,426,936
11	6.125% SERIES B	3,435,743
12	6.000% SERIES C	3,779,170
13	SERIES D Preference Stock (Proposed Issuance) - Rating Agency Fees	111,256
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	14,566,180

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	First and Refunding Mortgage Bonds:		
3	Series 2004A 5.0	300,000,000	2,074,000
4			1,306,366 D
5	Series 2004B 6.0	525,000,000	4,809,750
6			8,661,850 D
7	Series PV 2000AB 5.0	144,400,000	800,000
8			
9	Series 2004F 4.65	300,000,000	1,830,000
10			2,996,350 D
11	Series 2004G 5.75	350,000,000	3,062,500
12			2,657,584 D
13	Series 2005A 5.0	400,000,000	2,896,154
14			132,000 D
15	Series 2005B 5.55	250,000,000	2,341,346
16			732,500 D
17	Series 2005E 5.35	350,000,000	3,062,500
18			168,000 D
19	Series 2005A&B 3.55	203,460,000	2,600,000
20			
21	Series 2005 A,B & C Variable	248,585,000	2,100,000
22			
23	Series 2006A 5.625	350,000,000	3,430,000
24			857,500 D
25	Series 2006A&B 4.10	196,000,000	2,183,000
26			
27	Series 2006C&D 4.25	135,000,000	1,517,000
28			
29	Series 2006E 5.55	400,000,000	4,000,000
30			2,176,000 D
31	First and Refunding Mortgage Bonds Continued:		
32			
33	TOTAL	8,552,604,000	120,220,904

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	Series 2008A 5.95	600,000,000	2,760,000 D
2			6,350,000
3	Series 2008B 5.50	400,000,000	2,272,000 D
4			3,250,000
5	Series 2008C 5.75	500,000,000	2,540,000 D
6			3,800,000
7	Series 2009A 6.05	500,000,000	4,095,000 D
8			4,375,000
9	Series 2009B 4.15	250,000,000	35,000 D
10			1,500,000
11	Series 2010A 5.50	500,000,000	6,015,000 D
12			5,350,000
13	Series 2010B 4.50	500,000,000	3,180,000 D
14			5,325,000
15	Mohave 2010 .65	75,000,000	300,000
16			
17	SONGS 2010A 4.50	100,000,000	2,000,000
18			
19			
20	SUBTOTAL Account 221	7,577,445,000	109,541,400
21			
22	Account 222		
23	Series 2005 A, B, & C Variable	248,585,000	
24			
25	Clark County 2000A, B & C Variable	75,000,000	
26			
27			
28	SUBTOTAL- Account 223	323,585,000	
29			
30	Account 223		
31			
32			
33	TOTAL	8,552,604,000	120,220,904

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	SUBTOTAL- Account 223		
2			
3	Account 224		
4	Other Long-Term Debt:		
5			
6	6.65% Notes 6.650	300,000,000	1,462,000
7			3,615,000 D
8	Ft. Irwin Loan 5.06	7,734,000	
9			
10	Pollution Control Indebtedness:		
11			
12	Four Corner Series 99-A 5.125	55,540,000	769,000
13			381,004 D
14	Calif Pol Cntrl Refunding Revenue		
15	SONGS 99C 5.550	30,000,000	3,000,000
16			
17	HUNT BCH 99D 5.20	8,300,000	
18			
19	7 5/8% Notes 7.625	250,000,000	827,500
20			625,000 D
21			
22	Capitalized Interest Related to Nuclear Fuel		
23			
24	SUBTOTAL- Account 224	651,574,000	10,679,504
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	8,552,604,000	120,220,904

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
01/14/04	01/15/14	01/14/04	1/15/14	300,000,000	15,000,000	3
						4
01/14/04	01/15/34	01/14/04	01/15/34	525,000,000	31,500,000	5
						6
03/01/04	03/01/09	03/01/04	3/1/09	144,400,000	4,291,889	7
						8
03/23/04	04/01/15	03/23/04	04/01/15	300,000,000	13,950,000	9
						10
03/23/04	04/01/35	03/23/04	04/01/35	350,000,000	20,125,000	11
						12
01/19/05	01/15/16	01/19/05	01/15/16	400,000,000	20,000,000	13
						14
01/19/05	01/15/36	01/19/05	01/15/36	250,000,000	13,875,000	15
						16
06/27/05	7/15/35	6/27/05	07/15/35	350,000,000	18,725,000	17
						18
03/23/05	04/01/10	03/23/05	04/1/10	203,460,000	6,192,814	19
						20
08/31/05	08/01/35	08/31/05	08/31/35	248,585,000		21
						22
01/31/06	02/1/36	01/31/06	02/01/36	350,000,000	19,687,500	23
						24
04/12/06	4/1/28	04/12/06	4/1/28	196,000,000	8,036,000	25
						26
04/12/06	11/1/33	04/12/06	11/1/33	135,000,000	5,737,500	27
						28
12/11/06	01/15/37	12/11/06	1/15/37	400,000,000	22,200,000	29
						30
						31
						32
				7,654,643,845	381,657,443	33

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.
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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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
01/22/08	02/1/38	01/22/08	02/01/38	600,000,000	35,700,000	1
						2
08/18/08	08/15/18	8/18/08	08/15/18	400,000,000	22,000,000	3
						4
10/15/08	03/15/14	10/15/08	03/15/14	500,000,000	28,750,000	5
						6
03/20/09	03/15/39	03/20/09	03/15/39	500,000,000	30,250,000	7
						8
03/20/09	09/15/14	03/20/09	09/15/14	250,000,000	10,375,000	9
						10
3/11/10	03/15/40	03/11/10	03/15/40	500,000,000	22,152,778	11
						12
08/30/10	09/01/40	08/30/10	09/01/40	500,000,000	9,176,397	13
						14
12/16/10	05/03/11	12/16/10	05/03/11	75,000,000		15
						16
09/21/10	09/01/29	9/21/10	09/01/29	100,000,000	5,212,358	17
						18
						19
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	7,577,445,000	362,937,236	20
						21
						22
04/01/99	04/01/29	04/01/99	04/01/29	-248,585,000		23
						24
09/01/03	09/01/53	09/01/03	09/01/53	-75,000,000		25
						26
						27
				-323,585,000		28
						29
						30
						31
						32
				7,654,643,845	381,657,443	33

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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
						4
						5
04/01/99	04/01/29	04/01/99	04/01/29	300,000,000	19,950,000	6
						7
09/01/03	09/01/53	09/01/03	09/01/53	6,943,845	352,598	8
						9
						10
						11
04/29/99	04/01/29	04/29/99	04/01/29	55,540,000	2,846,425	12
						13
						14
09/01/99	09/01/31	09/01/99	09/01/31	30,000,000	1,665,000	15
						16
09/01/99	09/01/15	09/01/99	09/01/15	8,300,000	431,600	17
						18
01/15/00	01/15/10	01/15/00	01/15/10		741,319	19
						20
						21
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx		-7,266,735	22
						23
				400,783,845	18,720,207	24
						25
						26
						27
						28
						29
						30
						31
						32
				7,654,643,845	381,657,443	33

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 2 Column: a

- (1) All mortgage bonds are secured by utility plant, substantially all of which is subject to a lien under the trust indentures. Additional First and Refunding Mortgage Bonds, including additional bonds equal in principal amount to bonds retired, may be issued subject to the provisions of the applicable trust indentures. Each of the bond indentures requires special deposits with the trustees, which are based primarily upon the amount of bonds outstanding. These deposit requirements were satisfied by property additions and replacements.
- (2) Maturities and sinking fund requirements of long-term debts for the five years subsequent to December 31, 2010 will be: \$0 for 2011; \$0 for 2012; \$0 for 2013; \$1,050,000,000 for 2014 and \$308,300,000 for 2015.
- (3) Reacquisition expenses associated with long-term debt issues reacquired prior to maturity, including unamortized premium, discount and issuance expense pertaining to the retired indebtedness, are amortized over the remaining lives of the retired indebtedness when reacquired without refunding and over the lives of the new debt issues when reacquired with refunding.
- (4) During 2010, respondent capitalized a portion of interest expense on long-term debt for the purpose of financing the Company's nuclear fuel inventory. For 2010 the capitalized interest related to Nuclear Fuel totaled \$7,266,735.

Reconciliation of Interest Expense on long-term debt:

Account 427 -	
Interest on long-term debt	381,657,443
Capitalized Interest on LTD	<u>37,860</u>
	<u>381,695,303</u>

Schedule Page: 256.2 Line No.: 4 Column: a

- (1) All mortgage bonds are secured by utility plant, substantially all of which is subject to a lien under the trust indentures. Additional First and Refunding Mortgage Bonds, including additional bonds equal in principal amount to bonds retired, may be issued subject to the provisions of the applicable trust indentures. Each of the bond indentures requires special deposits with the trustees, which are based primarily upon the amount of bonds outstanding. These deposit requirements were satisfied by property additions and replacements.
- (2) Maturities and sinking fund requirements of long-term debts for the five years subsequent to December 31, 2010 will be: \$0 for 2011; \$0 for 2012; \$0 for 2013; \$1,050,000,000 for 2014 and \$308,300,000 for 2015.
- (3) Reacquisition expenses associated with long-term debt issues reacquired prior to maturity, including unamortized premium, discount and issuance expense pertaining to the retired indebtedness, are amortized over the remaining lives of the retired indebtedness when reacquired without refunding and over the lives of the new debt issues when reacquired with refunding.
- (4) During 2010, respondent capitalized a portion of interest expense on long-term debt for the purpose of financing the Company's nuclear fuel inventory. For 2010 the capitalized interest related to Nuclear Fuel totaled \$7,266,735.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/18/2011	2010/Q4
FOOTNOTE DATA			

Reconciliation of Interest Expense on long-term debt:

Account 427 -

Interest on long-term debt	381,657,443
Capitalized Interest on LTD	<u>37,860</u>
	<u>381,695,303</u>

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 filed, 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)	1,091,619,871
2		
3		
4	Taxable Income Not Reported on Books	
5		486,441,932
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		547,828,210
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		394,012,667
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		1,781,921,998
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-50,044,652
28	Show Computation of Tax:	
29	Federal Tax at 35%	-17,515,628
30		
31	Other Reserves/Adjustments/Credits	
32		
33	TOTAL Federal Tax	-17,515,628
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/18/2011	2010/Q4
FOOTNOTE DATA			

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

Taxable Income Not Recorded on Books:

Easements (Quarterly) - NEW 09/08	90,517,000.00
Global Settlement	0.00
Interest Capitalized	109,485,579.74
Equity Earnings of Subsidiaries	0.00
EDRA	0.00
Electric Energy Transaction Admin B/A	0.00
ESMA	0.00
Gross Revenue Sharing Tracking Account	0.00
Interest on Tax Deficiencies/Refunds	132,294,679.00
Late Payment Charge Revenue	0.00
Leased Vehicles	36,000.00
Rollforward of Settled Federal Audits	6,405,081.00
Tax Assessments	147,703,592.00
	486,441,931.74

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

Deductions Recorded on Books not Deducted for Return:

Accrued Vacation Pay	1,077,841.12
A/C Cycling Balancing Account	0.00
Advanced Metering & Demand	0.00
Advanced Metering Infrastructure M/A	0.00
Advanced Meter BA (NEW in 8/08)	0.00
Bond Discount Amortization	340,000.00
CARE Adjustment	1,527,425.65
Catastrophic Memo Account	0.00
Catastrophic Memo Account (CEMA L/T)	13,532,921.80
Clean Technology Generation B/A (CTGBA) - new 4/08	591,599.37
Qtrly Compl. Filings Audit M/A (new in 12/06)	0.00
Demand Response Program B/A	0.00
Self-Generation M/A	0.00
Debt Issuance Cost Amortization (new in 9/07)	500,000.00
NQ Decomm Expense	736,354.56
Decomm Trust Earnings - Book	180,706.08
Decomm expenses pd with NQ funds	0.00
Decomm expenses pd with Qualified funds	(470,561.32)
Decomm funds withdrawn from Qualified trust	0.00
NQ Decomm Trust Taxable Earnings	1,325,473.68
Deferred Credit (NEW IN 12/07)	0.00
DSMAC Expenses	0.00
DSM - Energy Efficiency Program	0.00
DSM - Low Inc Energy Efficiency Program	0.00
DSM - Care	0.00
DOE Litigation M/A (new in 5/07)	93,488.20
Employee Safety & Distribution Incentive (SRPIM)	0.00
Energy Assistant Tracking Acc (new in 12/07)	0.00
Excess Compensation	0.00
Executive Incentive Awards - ST	8,429,025.42
Executive Incentive Awards - LT	(2,615,542.50)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/18/2011	2010/Q4
FOOTNOTE DATA			

Financial Reporting Presentation Reserve	1,209,759.29
Severance Accruals	1,710,180.00
Fuel Write-down - DFO	117,233.50
Fuel Write-down - LSFO	0.00
Stock Options - Expense Accrued to APIC	12,524,582.72
Health and Safety Reward	13,000,000.00
Hydrogen Energy California Account (new in 3/09)	13,520,879.03
ITCC Deposits	18,519.52
Legislative Expenses Unallow.	3,721,393.42
LT Proc Plan Tech Assistance MA (LTAMA)	167,641.07
Medical BA	6,607,344.74
Mohave Transition Costs	0.00
New System Generation M/A - ST	984,577.87
New System Generation M/A - LT (new 8/08)	0.00
Non Deductible Business Meals	6,700,000.00
Nuclear Decomm. Adjust. Mech. (NDAM)	61,202.15
Nuclear Unit Def Charges	131,405.73
Palo Verde Common	112,274.17
Penalties	(28,000.00)
Pension Reserves	2,692,060.33
Refunding & Retirement of Debt	19,147,694.26
Research and Development	1,136,061.40
Results Sharing M/A	316,534.07
Right of Way - APS	12,274,237.11
Rollforward of Settled Federal Audits	7,011,668.00
LLC -	6,294,201.81
Transmission Access Charge Balance	0.00
Uncollectible Accts. Reserve	31,944,536.53
Uncollectible Accounts - Damage Claim	1,066,954.40
Right of Way Amortization	0.00
Federal tax expense	380,136,537.02
	547,828,210.20

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

Income Recorded on Books not included in Return:

AFUDC - Debt	42,677,222.02
Reserve for Injuries and Damages	3,846,505.44
Restricted Stock	0.00
Right of Way Amort.	3,080,844.00
RRB-Amort.	0.00
Risk Mgmt Tools M/A	(0.00)
AFUDC - Equity	102,638,686.62
Agricultural Line Ext. M/A (new in 12/06)	0.00
RRB Reg Asset - Contra	0.00
RSBA	3,915,069.94
Stock Option Costs	8,859,826.49
Transmission Revenue Bal. Acct.	0.00
Uncollectible Accounts - OAR	0.00
Amortization of Debt Expense	74,186.14
WECC Statutory Costs (new in 12/07)	28,396.16
FC CPITAL LT (New 2009)	871,249.14
FHPMA LT (New 2009)	11,669,171.66
MRTUMA	19,868,268.59

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

RPACMA	400,886.64
Base Rate Performance M/A	0.00
Base Revenue Requirement	0.00
Calif Solar Initiative Prog M/A	0.00
Carbon Sequestration Evaluation M/A - ST (CSEMA) - new 4/08	0.00
Carbon Sequestration Evaluation M/A - LT (CSEMA) - new 8/08	0.00
FERC Ratemaking Unbilled Revenue	0.00
Clean Hydrogen Power Generation - ST (CHPG) - new 4/08	0.00
Clean Hydrogen Power Generation - LT (CHPG) - new 8/08	0.00
CRR Mark to Market (L/T) - New 5/08	0.00
Corporate Life Insurance Proceeds	1,079,614.25
Direct Access Customer Charge Revenue M/A	0.00
Financial Reporting Prsn Rsv (below the line)	0.00
Invest - Warranty Expense	0.00
Environmental Remediation	1,598,520.83
Environmental Remediation - Below the line	416,509.90
Earnings of Utility Subs	6,941,749.20
Energy Resource Recovery Account	0.00
ESOP Dividend Payment	29,526,775.00
Etiwanda Waste Water Line	28,000.00
Exchange Energy Provision	1,814,619.66
Other Haz Sub Cleanup MA - NEW 10/2007	0.00
Executive Retirement Provision	84,802.61
Family Energy Rate Assistance	0.00
Firm Transmission Rights (Balancing Acc)	0.00
Firm Transmission Rights (Others)	3,686,000.00
Fixed Costs (Below the Line)	193,207.43
Fixed Costs	7,102,993.05
GCAC	64,334.73
Haz Waste Bal Acct.	6,459,730.35
Other Regulatory Liab (fka Haz Waste Ins Recovery)	0.00
Int Exp - Preferred Stock Dividends	0.00
Key Person Life Insurance	25,432,290.84
Lease Acctng - PPBU - Long-term	(3,090,183.51)
Lease Acctng - PPBU - Short-term	3,090,183.51
NDSCMA - new 10/08	44,126.32
Mark to Market - Interest Rate Lock (new in 9/07)	0.00
Misc Reg Liab / Asset (fka ECAC Bal Acc)	2,493,116.42
Solar Photovoltaic Program MA (SPVPMA)	0.00
Mountain View - Subsidiary Income After Tax	0.00
Mohave B/A	2,207,174.64
New System Generation MA	0.00
MRTU (new in 12/07)	0.00
Nuclear Fuel Carrying Costs	7,266,734.38
Affiliate Transfer Fee M/A (new in 12/06)	0.00
PBOP	4,365,175.95
PBOP B/A	(9,274,170.17)
Pension Cost Balancing Account	(9,204,160.11)
Peaker Gen Memo Acct	0.00
Procurement Energy Eff B/A	0.00

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/18/2011	2010/Q4
FOOTNOTE DATA			

Project Devel Div. M/A (new in 12/06)	0.00
Project Devel Div. M/A (new in 12/06) - Long Term	207,133.64
Public Purpose Program Aid Mech.	107,213,829.82
RD&D Royalties M/A (new in 12/06)	0.00
Reliability Costs M/A (new in 12/06)	0.00
Renewable Trans. Feasibility Study MA - LT	0.00
Residential Energy Disconnections MA (REDMA) - LT	35,222.76
NQ Decomm Trust Taxable Earnings	0.00
PBOP - Nontaxable Receipts	0.00
Tax Exempt Interest - Other	0.00
Capital balancing accounts - normalized	6,299,023.00
	394,012,667.34

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

Deductions on Return not Charged Against Book Income:

Ad Val Lien Date Adj - Electric	18,476,894.34
Ad Val Lien Date Adj - Gas	2,058.00
Ad Val Lien Date Adj - OTHER	(118,206.77)
Ad Val Lien Date Adj - Water	13,026.00
Ad Val Lien Date Adj - Telecom	(113,158.69)
CIAC	25,867,346.51
ITCC	9,041,541.78
CWIP Balancing Account - ST (new in 03/08)	5,318,435.41
CWIP Balancing Account - LT(new in 08/08)	0.00
Depreciation - BOOK Electric ACRS	1,345,181,514.00
Depreciation - BOOK Electric Norm	228,955,551.00
Depreciation - BBOOK Electric - Variance	(498,252,401.05)
Depreciation - BOOK Gas	42,229.28
Depreciation - BOOK Other	117,968.33
Depreciation - BOOK Water	246,286.41
Depreciation - BOOK Telecom	914,197.93
Depreciation - Cal Electric	0.00
Depreciation - Cal Electric	0.00
Depreciation - Cal Gas	0.00
Depreciation - Cal OTHER	0.00
Depreciation - Cal Water	0.00
Depreciation - Cal Telecom	0.00
Removal Costs - Electric	215,566,803.00
Repair Allowance	64,085,369.49
Repair Deduction - CPUC (2009 Form 3115)	56,075,929.51
Repair Deduction - FERC (2009 Form 3115)	6,759,453.49
Retirement Adj - Repair 3115-CPUC	(3,301,022.25)
Retirement Adj - Repair 3115-FERC	(448,977.75)
Streetlights - Form 3115	100,000,000.00
Capitalized Software - ERP (Flowthru) - NEW IN 11/07	(7,147,656.42)
Capitalized Software - ERP (Normalized) - NEW IN 11/07	0.00
Capitalized Software - Others - NEW IN 11/07	28,479,216.99
Tax Assessments-Interest Expense	0.00
263a Adjustment (Quarterly)	96,365,032.00

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

CCFT Lag - Electric Current Year	(57,680,916.48)
CCFT Lag - Electric Prior Year	139,648,381.00
Electric Power Research Institute Credit	0.00
Manufacturer's Deduction - Sec. 199	0.00
Preferred Dividend Deduction	809,000.00
Rollforward of Settled Federal Audits - CA	7,011,668.00
Solar Photovoltaic Program MA (SPVPMA) - L/T	6,434.64
Other State taxes (Tax Assessments)	0.00
CCFT Lag - Electric Current Year	0.00
	0.00
	1,781,921,997.70

Schedule Page: 261 Line No.: 27 Column: b

Federal Taxable Income	(50,044,651.90)
	(50,044,651.90)

Schedule Page: 261 Line No.: 33 Column: a

The company files a consolidated tax return with its subsidiaries. The amounts set forth in this schedule have been determined on a separate return basis. Tax liabilities for each subsidiary listed below are determined and apportioned on a separate return basis and are included in the Equity Earnings of Subsidiary Companies on page 119 of this report

418.130 Energy Services Inc.	750,106
418.131 Contra Account Energy Services Earnings	0
456.913 Energy Services Inc.	0
	750,106
418.135 Edison Material Supply	6,294,202
418.136 Conral Account Edison Mission Supply	0
456.911 Edison Material Supply	0
	6,294,202
418.140 Mono Power Co.	(2,937)
418.141 Contra Account Mono Power Co.	0
456.917 Mono Power Co.	0
	(2,937)
418.150 Southern States Realty Co.	(97,782)
418.151 Contra Account Southern States Realty Co.	0
456.915 Southern States Realty Co.	0
	(97,782)
418.160 Conservation Financing Corp.	0
418.161 Contra Account Conservation	0

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Financing Corp		
456.916	Conservation Financing Corp.	0
		0
418.180	SCE Funding	0
418.181	Contra Account SCE Funding	0
456.918	SCE Funding	0
		0
418.190	SCE Capital Company	(1,840)
418.191	Contra Account SCE Capital Company	0
456.919	SCE Capital Company	0
		(1,840)
418.120	Mountain View Power	0
418.121	Contra Account Mountain View Power	0
		0
		0
456.912	SCE UK Services	0
		0

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 known, 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	FEDERAL TAXES:					
2						
3	Federal Income Taxes	-104,616,125		-171,177,694	2,086,027	125,890,907
4	Income Taxes	32,516,945				135,946,718
5	Fed Ins Cont Act- Current	524,315		123,142,307	-123,113,170	-182,129
6	Fed Ins Cont Act- Prior					
7	FICA/OASDI Emp Inctv	6,805,807		948,823		
8	FICA/HIT Emp Inctv	1,825,956		278,221		
9	Fed Unemp Tax Act- Current	42,659		1,071,004	-1,087,761	-1
10	Superfund Tax					
11						
12	SUBTOTAL- FED TAXES :	-62,900,443		-45,737,339	-122,114,904	261,655,495
13						
14	STATE TAXES :					
15						
16	CA Corp. Franchise Tax	47,965,568		-77,681,514	258,038,604	-247,723,377
17	Income Tax- Arizona	3,375,092		-476,538	-436,243	520,574
18	Income Tax- New Mexico	993,191		-496,970	-947,667	-520,574
19	Income Tax- Utah and	483		-483		
20	Income Tax- DC	-441,088		246,549	-79,500	
21						
22	Empl Tax-Arizona-Current					
23	CA SUI Current	91,338		4,275,168	-4,266,769	1
24	CA ET- Current					
25	SUI Florida-Current (EME)					
26	SUI Missouri					
27	SUI R.I. (Source)					
28	SUI WI					
29	EMOM MN SUI TAX	251				
30	SUI Mass- Current (EC)	5,676				
31	SOURCE KY SUI TAX					
32	ENOM NM SUI TAX					
33	ENOM IA SUI TAX					
34	ED. SUPPLY NV SUI TAX					
35	SUI TAX - NEVADA					
36	NV SUI TAX (SOURCE)					
37	SUI NEVADA - CURRENT	110,714		2,917	-3,017	
38	SUI New York-Current					
39	SUI Texas- EMOM	-303				
40	SUI Texas- Current					
41	TOTAL	8,875,809	-1,350,685	199,567,602	-177,901,183	13,640,934

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 known, 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1						
2	SUI OK- Current (EC)					
3	SUI OR-Current (Source)					
4	SUI Virginia-Current					
5	STATE TAXES (cont):					
6	ACCD SUI TAX - WASH D.C.					
7	D.C. SUI TAX -EME	213		-79	-80	
8	SUI Tax DC-Current					
9	SUI W. Vir-Current(EME)					
10	HOMER CITY PA SUI					
11	EME FS. PA SUI TAX					
12	EMMT PA SUI TAX					
13	PA SUI TAX MOMI					
14	SUI Pennsylvania-Current	-22			822	
15	MWG IL SUI TAX					
16	MG EME IL SUI TAX					
17	EME SERVICES IL SUI TAX					
18	EMMT IL SUI TAX					
19	SUI ILLINOIS MEC					
20	SUI Illinois-Current(Source)	19,010		321	-192	
21	SUI Georgia-Current(Source)					
22	SUI NJ-Current(Source)	-61				
23	NY SUI TAX - EMMT	-6				
24	SUI Colo-Current(Source)					
25	SUI Hawaii- Current(Source)					
26	SUI Idaho- Current (Source)					
27	SUI N Mex-Current(Source)					
28	SUI Wash-Current(Source)					
29	WY SUI TAX - EMOM	348				
30	SUI Wyoming-Current					
31	SUI MI-Current(Source)	3				
32	SUI South Carolina					
33	SUI CT (Select)					
34	SUI IA O&M					
35	SUI IAX					
36	MA Hlth INS TX - EMMT	-172				
37	SF Pysl Exp Tx - SCE	41,393		27,660	92	-2
38	EMG Pysl Tax Pay Recl	-56,935				-341,777
39	CADI Vol Plan Assess	-2,547,222		4,256,704	-1,726,978	-1
40						
41	TOTAL	8,875,809	-1,350,685	199,567,602	-177,901,183	13,640,934

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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
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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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Use Tax-Arizona-Prior					
2						
3	Use Tax-Arizona-Current					
4	Use Tax-California-Prior					
5	Use Tax-California-Current	78,135		5,088,266	-5,083,535	
6	Use Tax-New Mexico-Prior					
7	SALES TAX ACCRUED	22,036,748		117,654,060	-109,395,634	
8	Sales Tax Payable - CA	53,378		9,459	-61,443	-1
9	Sales Tax Payable - District	9,637		3	-9,639	-1
10	Sales Tax-O&M Services	-1,198				
11	Accrued District/Local use CA	9,551		58,705	-52,607	-6,275
12	Sales Tax Accrued/ Contra					
13						
14	SUBTOTAL-STATE TAXES:	71,743,722		52,964,228	135,976,214	-248,071,433
15						
16	LOCAL TAXES:					
17						
18	Property Tax-Ariz Current			3,606,998		-3,606,998
19	Property Tax-Ariz Prepaid			3,971,991	-7,578,989	3,606,998
20	Property Tax-Calif Current			89,595,779		-89,257,682
21	Property Tax-Calif Prepaid		-1,201,715	86,958,945	-176,244,280	89,242,718
22	Property Tax-D.C. Current					
23	Property Tax-Nevada Current			48,139		-48,139
24	Property Tax-Nevada Prepaid		-148,970	527,074	-657,437	119,975
25	Property Tax-N Mex Current			3,571,822		-3,571,822
26	Property Tax-N Mex Prepaid			3,359,965	-6,931,787	3,571,822
27	Accrued Tax Liab.Not					
28	Charged to Inc.					
29	Hazardous Waste	32,530				
30	Use Tax-Nevada-Prior					
31	Use Tax-Nevada-Current					
32	Use Tax-LA County-Prior					
33	Use Tax- LA County Current					
34	Use Tax-Nuclear Fuel					
35	Bus. Activity Tax - Navajo			700,000	-350,000	
36						
37	SUBTOTAL- LOCAL TAXES	32,530	-1,350,685	192,340,713	-191,762,493	56,872
38						
39						
40						
41	TOTAL	8,875,809	-1,350,685	199,567,602	-177,901,183	13,640,934

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
-147,816,885		-138,839,008			-32,338,686	3
168,463,663						4
371,323		122,975,164			113,670	5
						6
7,754,630		1,001,856				7
2,104,177		133,574				8
25,901		1,070,015			988	9
						10
						11
30,902,809		-13,658,399			-32,224,028	12
						13
						14
						15
-19,400,719		-68,879,502			-8,802,012	16
2,982,885		-476,538				17
-972,020		-496,970				18
		-483				19
-274,039		246,549				20
						21
						22
99,738		4,274,380			3,946	23
						24
						25
						26
						27
						28
251						29
5,676						30
						31
						32
						33
						34
						35
						36
110,614						37
						38
-303						39
						40
44,236,166	-1,403,690	95,969,530			103,452,983	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

- If any tax (exclude Federal and State income taxes)- covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
- 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.
- 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.
- 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.
- 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
						2
						3
						4
						5
						6
54		-321				7
						8
						9
						10
						11
						12
						13
800						14
						15
						16
						17
						18
						19
19,139		321				20
						21
-61						22
-6						23
						24
						25
						26
						27
						28
348						29
						30
3						31
						32
						33
						34
						35
-172						36
69,143		27,660				37
-398,712						38
-17,497		4,256,704				39
						40
44,236,166	-1,403,690	95,969,530			103,452,983	41

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
						4
82,866					5,088,266	5
						6
30,295,174					117,654,060	7
1,393					9,459	8
		3				9
-1,198						10
9,374					58,705	11
						12
						13
12,612,731		-61,048,197			114,012,424	14
						15
						16
						17
		4,144,781			6,803	18
		3,414,396			13,009	19
		79,041,289			10,554,490	20
338,096		76,492,455			10,466,490	21
	-1,244,332					22
		46,672			1,467	23
	-159,358	482,228			44,846	24
		3,272,717			299,105	25
		3,081,588			278,377	26
						27
						28
32,530						29
						30
						31
						32
						33
						34
350,000		700,000				35
						36
720,626	-1,403,690	170,676,126			21,664,587	37
						38
						39
						40
44,236,166	-1,403,690	95,969,530			103,452,983	41

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		96,642,359	410/411	28,232,077	410/411	7,340,905	848,176
8	TOTAL	96,642,359		28,232,077		7,340,905	848,176
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
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45							
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47							
48							

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
			5
			6
118,381,707	17		7
118,381,707			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
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			40
			41
			42
			43
			44
			45
			46
			47
			48

OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Advance on Jobbing Accounts	137,222,173	Various	22,939,175	26,638,377	140,921,375
2						
3						
4	Miscellaneous					
5	Deferred Credits	57,324,512	Various	126,861,839	135,913,249	66,375,922
6						
7	Accrued tax liabilities - LT	5,930,841	Various	836,831,649	830,900,813	5
8						
9	Miscellaneous Work In Progress	268,492,553	Various	41,429,420	68,206,776	295,269,909
10						
11	Lease Payable - Long-Term	48,889,459	Various	9,365,196	2,627,696	42,151,959
12						
13	Income Tax Component of					
14	Contributions in Aid of					
15	Construction	178,491,695	Various	1,314,210,115	1,297,209,390	161,490,970
16						
17	SONGS 1 Decommissioning -					
18	amount to be amortized over a 21					
19	year period beginning January 1993					
20	to December 2013.		Various	1,169,844	1,169,844	
21						
22	Environmental Remediation	38,893,237	Various	27,032,409	41,800,452	53,661,280
23						
24	TDBU Collateral	1,276,453	Various	3,351,860	13,311,200	11,235,793
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	736,520,923		2,383,191,507	2,417,777,797	771,107,213

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6	NONE			
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 272 Line No.: 6 Column: a
NO ACTIVITY IN 2010

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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	2,196,379,359	800,000,911	293,979,501
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	2,196,379,359	800,000,911	293,979,501
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	2,196,379,359	800,000,911	293,979,501
10	Classification of TOTAL			
11	Federal Income Tax	2,196,379,359	800,000,911	293,979,501
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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
				Various	13,954,743	2,716,355,512	2
							3
							4
					13,954,743	2,716,355,512	5
							6
							7
							8
					13,954,743	2,716,355,512	9
							10
					13,954,743	2,716,355,512	11
							12
							13

NOTES (Continued)

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Detail Attached	2,678,520,732	1,293,544,536	965,830,662
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,678,520,732	1,293,544,536	965,830,662
10	Gas			
11	See Detail Attached	540,491	56,320	40
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	540,491	56,320	40
18	Other (See Detail Attached)	133,105,934	36,496,315	42,613,123
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	2,812,167,157	1,330,097,171	1,008,443,825
20	Classification of TOTAL			
21	Federal Income Tax	2,812,167,157	1,330,097,171	1,008,443,825
22	State Income Tax			
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				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
		VARIOUS	66,803,481	VARIOUS	61,992,497	3,001,423,622	3
							4
							5
							6
							7
							8
			66,803,481		61,992,497	3,001,423,622	9
							10
		VARIOUS	33,681	VARIOUS		563,090	11
							12
							13
							14
							15
							16
			33,681			563,090	17
		VARIOUS	2,547,756	VARIOUS	40,931,805	165,373,175	18
			69,384,918		102,924,302	3,167,359,887	19
							20
			69,384,918		102,924,302	3,167,359,887	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/18/2011	2010/Q4
FOOTNOTE DATA			

Schedule Page: 276 Line No.: 3 Column: a

ELECTRIC:		
190.400	GRC Memo Account	-
190.900	Four Corners Capital	-
283.000	Advance Meter BA	-
283.000	Def Tax State - Other (GSI)	(1,089,589)
283.000	Lease Acctng - PPBU - Short-term	181,207
283.000	Medical B/A (new 12/08)	-
283.000	Reg Asset - Deferred Tax - Temp	1,798,011
283.000	Regulatory Receivable - CCFT BASE	-
283.000	Smart Connet B/A (new in 10/08)	-
283.000	Solar Photovoltaic Program MA (SPVPMA)	(1,168,845)
283.112	Balancing Account Overcollection	(24,742,915)
283.120	Other Current & Accrued Liabilities	-
283.133	EDRA	(1,392,068)
283.142	Payroll Tax	(1,930,349)
283.203	Mohave Transition Costs	(178,094)
283.214	Ad Valorem Lien Date Adj-Electric	(63,401,089)
283.214	AdVal - Electric	-
283.275	Gross Revenue Sharing Tracking Account	-
283.287	Health and Safety Reward	-
283.288	Firm Transmission Rights (Other)	2,333,645
283.289	Procurement Energy EFF BA	30,008,420
283.289	ST Gen Capacity Memo Acct	-
283.301	Misc Reg Liab/Asset (fka ECAC Bal Acct)	12,493,325
283.304	Base Rate Performance MA	(0)
283.304	Base Rate Performance MA	-
283.305	Calif Solar Initiative Prog M/A	-
283.306	MERMA	-
283.367	Advanced Metering Infrastructure M/A	-
283.376	Haz Waste Bal Acct. - 182.376 & 254.376	(3,502,863)
283.384	Ad Valorem Lien Date - Plant Sale	(2,215,619)
283.384	Ad Valroem Lien Date - Plant Sale	-
283.386	Residential Generation Revenue S/F	-
283.386	TCBA	-
283.389	Transmission Revenue Balancing Acct.	-
283.389	Transmission Revenue Balancing Acct.	-
283.400	Clean Technology Generation B/A (CTGBA)	-
283.402	Rate Reduction Bond - Amortization	-
283.402	Rate Reduction Bond Ratepayer Saving	-
283.402	RRB Regulatory Asset - Contra Account	-
283.403	Risk Management Tools M/A - ST	-
283.405	Catastrophic Memo Account	-
283.417	Late Payment Charge Revenue	-
283.419	A/C Cycling Balance Account	-
283.420	Electric Energy Transaction Admin	-
283.421	Advance Metering & Demand	-
283.423	Transmission Access Charge Balance	-
283.424	Real Time Energy Metering Account	(5,453,408)
283.424	RRB Regulatory Asset - Contra Account	-
283.427	CARE Adjustment (Formerly LISAC)	(22,455,158)
283.433	Public Purpose Program Aid Mech.	-
283.434	Native Load Balance Account	-
283.435	Duke Settlement	-
283.436	Energy Resource Recovery Account	-
283.436	FERC transmission refunds	-
283.443	Base Revenue Requirement BA	-

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			

FOOTNOTE DATA

283.448	Trade Receivable	-
283.453	RSBA	(1,704,363)
283.461	ESMA	-
283.462	ESMA - Dynergy	(3,787,629)
283.463	ESMA - PS Colorado	(2,872,429)
283.464	ESMA - Duke	(3,868,140)
283.465	ESMA - Mirant Settlement	-
283.466	ESMA - Reliant	(46,248,870)
283.467	ESMA - Enron Settlement	(37,579,769)
283.468	ESMA - IdaCorp	-
283.469	ESMA - PS Colorado Settlement	(841,256)
283.470	Pension Cost Balancing Account	(6,553,748)
283.471	PBOP B/A	0
283.472	Results Sharing M/A	0
283.473	Mohave B/A	(897,658)
283.474	Direct Access Customer Charge Revenue M/A	-
283.475	Res Def Rev M/A (RDRMA)	-
283.476	Agricultural Line Ext. M/A	-
283.477	Project Devel Div. M/A	(3,186,540)
283.477	Project Devel Div. M/A	(84,241)
283.478	Compl. Filings Audit M/A - Qtrly	-
283.479	Reliability Costs M/A	-
283.481	Affiliate Transfer Fee M/A	-
283.482	RD&D Royalties M/A	-
283.484	DIT DOE Litigation MEMO Account - New 2008	107,761
283.488	Peaker Gen Memo Acct	-
283.489	Other Haz Sub Cleanup M/A	-
283.494	CWIP Balancing Account - ST	(4,284,318)
283.495	New System Generation M/A - ST	(16,581,189)
283.496	MRTU MA	0
283.496	MRTU MA (New 11/09)	0
283.497	Clean Technology Generation B/A (CTGBA)	-
283.498	Carbon Sequestration Evaluation M/A ST (CSEMA)	-
283.499	Clean Hydrogen Power Generation (CHPG) - ST	-
283.500	DIT AIMMA	24,640,579
283.502	LT Proc. Plan Tech Assistance M/A (LTAMA)	(12,718)
283.640	DSM Incentive	-
283.700	Mark to Market - Interest Rate Lock	-
283.970	Uncollectible Accounts - OAR	-
283.970	Uncollectible Accounts - OAR	-
283.970	Uncollectible Accts. - OAR	-
283.823	CONTRA DIT - BALANCING ACCT (STATE - S/T)	-
283.823	CONTRA DIT - CAP SOFTWARE (STATE - S/T)	-
283.823	CONTRA DIT - CCFT (STATE - S/T)	-
283.823	CONTRA DIT - OTHER (STATE - S/T)	-
283.823	CONTRA DIT - PROPERTY (STATE - S/T)	-
283.823	CONTRA DIT - TAX ON INTEREST (STATE - S/T)	-
190.000	Solar Investment Tax Credit - Basis Adj (new 12/08)	-
190.000	Writeoff Victor Kramer DTA	-
283.000	Carbon Sequestration Evaluation M/A LT (CSEMA)	-
283.000	Clean Hydrogen Power Generation (CHPG) - LT	-
283.000	CWIP Balancing Account - LT	-
283.000	NDSCMA - (New 10/08)	(28,735)
283.000	New System Generation M/A - LT (new 8/08)	-
283.000	Regulatory Liability LT	-
283.000	Renewable Trans. Feasibility Study MA - LT	-
283.116	Marine Mitigation	0
283.122	Amortization of Debt Expense	988,136

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

283.143	Refundable Receivable Line Extension	304,244
283.145	DOE Decontamination & Decommissioning	2,282,911
283.209	Cum. Effect - FAS 109-SONGS NUC DBD Csts	(1,592,868)
283.212	263A Adjustment	(10,484,486)
283.215	AFUDC - Equity	(314,757,248)
283.221	CIAC-Deferred Rev-FAS 109 Gross-up	77,385,710
283.227	Depreciation - Cal - Electric	(1,004,125,708)
283.235	Removal Costs - Electric	(233,272,113)
283.236	Repair Allowance	(162,767,326)
283.238	Right of Way Amort.	(4,677,797)
283.239	Salvage Warehouse Expense	-
283.245	Unreal Gain - Decom - Q - Invest	(389,309,625)
283.245	Unrealized Gain - Deom - NQ - Invest	-
283.246	Capitalized Software - Others - NEW IN 11/07	(137,769,183)
283.246	Capitalized Software Costs - Tax	(3,971,309)
283.247	Capitalized Software Costs	(100,152,677)
283.251	Repair - CPUC Depr Recap Repair Recharaterization	-
283.252	Repair - CPUC Repair Deduction	-
283.252	Repair - CPUC Repair Deduction	(322,149,765)
283.253	Repair - Contra Defferreds/Repair Deduction Reserve	135,740,331
283.259	Capitalized Software - ERP (Flowthru) - NEW IN 11/07	(125,259)
283.259	Capitalized Software Costs - ERP	(49,489,713)
283.262	Lease Acctng - PPBU - Long-term	(181,207)
283.318	Nuclear Unit Deferred Chges	(1,111,428)
283.324	ITC - Deferred Tax - Plant Sale	10,930,907
283.325	Radio Frequency	(5,520,342)
283.326	Decomm Trust Earnings - Book	(37,716,435)
283.327	Contribution to Qualified Decommissioning Trust	(4,079,831)
283.398	ARAM - Plant Sale	(115,892,045)
283.340	Depreciation - Book - Plant Sale	-
283.340	Sale - Alamitos - Plant Related	-
283.340	Sale - Huntington - Plant Related	-
283.340	Sale - Other - Plant Related	-
283.385	TCBA Cost	-
283.385	TCBA Revenue Account	(17,446,268)
283.390	Environmental Remediation	-
283.390	Environmental Remediation - Below the Line	7,453,668
283.393	SFAS 158 - Long Term	(3,355,098)
283.395	Environmental Remediation	-
283.395	Non Collaborative Environmental Remediation-Reg. Asset	-
283.412	FERC South Georgia	(27,716,155)
283.484	DOE Ligtigation M/A	(272,393)
283.503	Purchase Agreemt Admin Costs BA - PAACBA	-
283.525	Palo Verde Common	(695,629)
283.669	Catastrophic Memo Account (CEMA L/T)	(8,708,658)
283.731	Refunding & Retirement of Debt	(93,317,290)
283.960	Environmental Remediation - Others	-
283.824	CONTRA DIT - BALANCING ACCT (STATE - L/T)	-
283.824	CONTRA DIT - CAP SOFTWARE (STATE - L/T)	-
283.824	CONTRA DIT - CCFT (STATE - L/T)	-
283.824	CONTRA DIT - OTHER (STATE - L/T)	-
283.824	CONTRA DIT - PROPERTY (STATE - L/T)	-
283.824	CONTRA DIT - TAX ON INTEREST (STATE - L/T)	-
283.823	RECLASS FIN48 Q4 BALANCE	(445,326)
283.824	RECLASS FIN48 Q4 BALANCE	(907,698)
	TOTAL ELECTRIC	(3,001,423,622)

Schedule Page: 276 Line No.: 11 Column: a

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

GAS		
283.211	Ad Valorem Lien Date Adj-Gas	(15,961)
283.228	Depreciation - Cal - Gas	(520,963)
283.300	GCAC	(26,166)
	Total Gas	(563,090)

Schedule Page: 276 Line No.: 18 Column: a

OTHER INCOME		
283.213	Ad Valorem Lien Date Adj-Water	(79,628)
283.553	ENVEST - Bad Debt	172,774
283.226	Depreciation - Book - Other	(166,335,087)
283.226	Depreciation - Cal - Other	-
283.226	Easements (new in 9/08)	-
283.229	Depreciation - Cal Water	1,252,401
283.242	Executive Retirement Provision	(1,106,823)
283.242	Health Care Reserve	-
283.257	CFC Capital Loss	(2)
283.258	Capitalized Software Costs - Normalized	4,057,792
283.283	Depreciation - Book - Telecom	(3,519,074)
283.283	Depreciation - Book - Telecom	177,407
283.283	Depreciation - Cal Telecom	-
283.295	Telecom - Deferred Tax on Reg Asset	7,067
283.557	Depreciation - BOOK - ENvest	-
283.557	Depreciation - Cal - ENvest	-
283.557	ENVEST - Warranty Expense	-
	Total Other	(165,373,175)

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Research Development and Demonstration	1,087,540	407	1,366,901	978,051	698,690
2	Balancing Account					
3	To track Commission authorized funding and re-					
4	cord the difference between revenues and costs					
5	associated with RD&D.					
6						
7	Demand Reduction and Self-Generation Program	145,322,013	407	603,886	23,954,155	168,672,282
8	Incremental Cost (DRSGPIC) Memorandum Account					
9	To track the recorded incremental program costs					
10	and distribution revenue requirement recorded in					
11	the Base Revenue Requirement Balancing Acct					
12	(BRRBA) associated with SCE's Small Commercial					
13	Demand Responsiveness Pilot Program and the					
14	Self-Generation Pilot Program authorized by the					
15	CPUC.					
16						
17	Demand Side Management Adjustment Clause	7,016,841	407	21,390	18,305	7,013,756
18	Balancing Accounts					
19	To track Commission authorized funding and					
20	record the difference between revenues and costs.					
21						
22						
23	Energy Efficiency Program Adj. Mechanism	94,657,629	407	343,822	47,803,090	142,116,897
24	To track the Public Purpose Program Charge					
25	Funds allocable to the 1998 energy efficiency					
26	programs/expenses, and establish the Energy					
27	Efficiency Program Incentive procedure.					
28						
29	Low Income Program Adjustment Mechanism	13,953,578	407	10,067,017	3,567,220	7,453,781
30	To track the Public Purpose Program Charge Funds					
31	allocable to the 1998 low income programs, and					
32	the 1998 low income energy efficiency program					
33	expenses.					
34						
35	Insurance Settlements	5,780	Various	5,780		
36	Ratepayer portion of environmental insurance					
37	settlements.					
38						
39	Electric Deferred Refund Account	9,503,772	Various	11,744,658	9,195,743	6,954,857
40	To reflect refund of various disallowances with					
1	interest incurred through December 31, 1996 to					
2	ratepayers as per Advice Letter No. 1280-E.					
3	Procurement Energy Efficiency Balancing Acct.	52,092,534	Various	50,431,606	95,182,886	96,843,814
4	To track the difference between actual incremen-					
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
5	tal procurement related energy efficiency costs					
6	and authorized procurement related energy					
7	efficiency revenues per D.03-12-062.					
8						
9	Energy Settlements Memorandum Account (ESMA)	28,975,662	Various	74,729,969	61,812,383	16,058,076
10	To record refund amounts received by SCE					
11	resulting from FERC investigation settlement					
12	agreements associated with wholesale power					
13	purchases made on behalf of SCE's bundled					
14	service customers, net of litigation costs re-					
15	corded in the Litigation Costs Tracking Account.					
16						
17	Base Revenue Requirement Balancing Account	151,919,905	Various	401,748,722	420,757,502	170,928,685
18	To record the difference between SCE's					
19	distribution, generation, and recorded revenue					
20	requirements and other amounts authorized by the					
21	Commission.					
22						
23	Asset Retirement Obligation (ARO)	171,462,548	Various	464,932,567	1,392,207,830	1,098,737,811
24	To establish a regulatory liability for					
25	decommissioning costs collected in rates					
26	for ARO assets.					
27						
28	Transmission Rev Balancing Acct Adj.	30,184,603	Various	28,025,563	6,253,751	8,412,791
29	To record transmission revenue credits,					
30	congestion revenue, wheeling revenue, sale of an					
31	FTR revenue, and ancillary service expense to					
32	the TRBAA.					
33						
34						
35	Exchange Energy		Various	4,501,458	4,501,458	
36	To record non-cash related energy costs not					
37	involving the transfer of cash between SCE and					
38	third parties.					
39						
40	FTR Costs	(1)		(1)		
1	To amortize the Firm Transmission Rights					
2	costs paid to the California Independent					
3	System Operator (CAISO).					
4	(Amortization Period: 04/2008-3/2009)					
5	Transmission and CPUC Related Ratemaking	33,147,315	Various	13,156,910	22,907,575	42,897,980
6	Reclassification of ancillary service amounts					
7	and ESMA - Net Litigation Costs to a liability					
8	account.					
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
9						
10	Energy Agreements Regulatory Account	34,735,360	Various	43,188,633	39,932,050	31,478,777
11	and Miscellaneous Regulatory Account					
12	To capture various accrued purchased power					
13	agreements & other miscellaneous Regulatory					
14	Liabilities					
15						
16						
17	Demand Response Program Balancing Account	35,802,697	Various	1,899,831	20,011,742	53,914,608
18	(DRPBA)					
19	To record the difference between the actual					
20	capital related revenue requirement and O&M costs					
21	incurred by SCE and the authorized Demand					
22	Response Revenue Requirement approved by the					
23	Commission in D.06-03-024 and in SCE's					
24	General Rate Case (GRC) proceedings.					
25						
26						
27	California Solar Initiative Program Bal Acct.	284,656,176	407	9,777,911	24,613,095	299,491,360
28	To track the recorded incremental California					
29	Solar Initiative Program costs and authorized					
30	distribution revenue requirement recorded in the					
31	Base Revenue Requirement Balancing Account					
32	(BRRBA) associated with SCE's California					
33	Solar Initiative Program.					
34	Energy Resource Recovery Account	45,862,644	Various	59,261,134	358,083,777	344,685,287
35	To record SCE's ERRRA Revenue, Utility					
36	Retained Generation fuel costs, and purchased					
37	power related expenses.					
38						
39						
40	Post Employment Benefits Other than Pensions		Various	6,501,649	11,393,839	4,892,190
1	(PBOP) Costs Balancing Account					
2	To record the difference between PBOP costs					
3	authorized by the Commission, and recorded					
4	PBOP expenses.					
5						
6						
7	Mohave Balancing Account	2,170,189	182	2,179,636	9,447	
8	To track the difference between: 1) recorded					
9	capital-related expenses, operating expenses and					
10	worker protection expenses associated with the					
11	Mohave Generating Station; and 2) the authorized					
12	Mohave revenue requirement as adopted in					
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
13	D.09-03-025.					
14						
15						
16	Affiliate Transfer Memorandum Account	231,985	Various	232,004	129,873	129,854
17	To record transfer fees received from affiliates					
18	when an employee is transferred, assigned, or					
19	otherwise employed by the affiliate.					
20						
21						
22	Energy Assistance Fund	18,000	407	18,000		
23	To record regulatory liability associated with					
24	the 2006 Energy Assistance Fund (EAF) rate relief					
25	program, and amounts disbursed to United Way, but					
26	not paid or pledged to rate relief customers.					
27						
28	Public Purpose Programs Adj. Mechanism	8,047,893	Various	84,606,275	76,558,382	
29	To record Public Goods Charge Revenue, PGC					
30	expenses authorized in P.U. Code Section 399.8,					
31	and other CPUC Public Purpose Program revenues					
32	and expenses.					
33	Reliability Service (RS) Balancing Account	(2)				-2
34	To track the RS revenues and RS costs to ensure					
35	that SCE neither over-collects nor under-collects					
36	RS costs assessed.					
37						
38	WECC Statutory Costs	4,774,160	407	4,774,160	4,676,097	4,676,097
39	To record WECC statutory fees being amortized					
40	over 12-month period.					
1						
2	Purchase Agreement Administrative Costs Balancing	1,118,557	Various	382,727	623,133	1,358,963
3	Account					
4	To record the difference between SCE's actual					
5	and authorized administrative costs associated					
6	with (4) third-party demand response contracts					
7	during the period March 13, 2008 through December					
8	31, 2012 in accordance with D. 08-03-017.					
9	Regulatory Liability - L/T	32,584,090				32,584,090
10	To capture various accrued purchased power					
11	agreements and other miscellaneous					
12	regulatory liabilities.					
13						
14	Palo Verde Balancing Account	31,022,509	254	38,797,140	38,417,422	30,642,791
15	To record the difference between the authorized					
16	and SCE's actual Operations and Maintenance(O&M),					
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
17	Administrative & General (A&G), Pension &					
18	Benefits (P&B), Payroll Taxes and oversight					
19	expenses.					
20						
21	GCAC Balancing Account	186,700	Various	609,704	423,004	
22	Balance composed of Gas Cost Adjustment Clause					
23	which recovers/refunds gas costs on					
24	Catalina Island.					
25						
26	Transmission Access Balancing Account	41,509,013	407	3,068,813	39,827,547	78,267,747
27	To track the flow through to end-use customers					
28	the net cost-shift billed to SCE by the ISO under					
29	the Transmission Access Charge (TAC) as per					
30	Section 5.6 of the TO Tariff.					
31	On-Bill Financing Balancing Account				5,339,817	5,339,817
32	To track all 2010-2012 OBF loans and					
33	repayments.					
34						
35	Gross Revenue Sharing Mechanism		Various	12,096,332	12,096,332	
36	To record the customer's share of certain Other					
37	Operating Revenue (OOR), as per Advice Letter					
38	No. 1413-E-A, dated September 16, 1999.					
39						
40	Medical Balancing Account		Various	2,002,169	11,102,423	9,100,254
1	To record the difference between the authorized					
2	and recorded Medical, Dental, Vision expenses in					
3	accordance with D. 09-03-025.					
4						
5	Nuclear Decommissioning Adjustment Mechanism				22,113,088	22,113,088
6	To record NDAM revenue, authorized and recorded					
7	costs related to the decommissioning of					
8	San Onofre Nuclear Generating Station and					
9	Palo Verde Nuclear Generating Station.					
10						
11	Results Sharing Memorandum Account (RSMA)		407	1,892,002	1,892,427	425
12	To track the difference between authorized and					
13	recorded Results Sharing expenses paid out.					
14						
15						
16						
17						
18						
19						
20						
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

Name of Respondent
Southern California Edison Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/18/2011

Year/Period of Report
End of 2010/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than \$100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
21						
22						
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33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,262,049,690		1,332,968,368	2,756,383,444	2,685,464,766

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	4,112,503,508	3,926,681,756
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	5,031,075,174	4,719,575,709
5	Large (or Ind.) (See Instr. 4)	777,729,130	734,263,049
6	(444) Public Street and Highway Lighting	108,198,700	100,911,901
7	(445) Other Sales to Public Authorities	6,349,194	2,197,265
8	(446) Sales to Railroads and Railways	7,710,877	7,257,769
9	(448) Interdepartmental Sales	277,660	231,321
10	TOTAL Sales to Ultimate Consumers	10,043,844,243	9,491,118,770
11	(447) Sales for Resale	176,835,806	205,825,616
12	TOTAL Sales of Electricity	10,220,680,049	9,696,944,386
13	(Less) (449.1) Provision for Rate Refunds	56,778,000	
14	TOTAL Revenues Net of Prov. for Refunds	10,163,902,049	9,696,944,386
15	Other Operating Revenues		
16	(450) Forfeited Discounts	17,192,992	16,626,634
17	(451) Miscellaneous Service Revenues	40,414,900	43,617,782
18	(453) Sales of Water and Water Power	479,531	829,271
19	(454) Rent from Electric Property	72,260,517	75,090,309
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	36,324,952	58,261,477
22	(456.1) Revenues from Transmission of Electricity of Others	61,498,082	51,427,673
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	228,170,974	245,853,146
27	TOTAL Electric Operating Revenues	10,392,073,023	9,942,797,532

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
29,032,685	30,046,635	4,277,734	4,254,956	2
				3
43,878,618	45,002,207	573,057	569,552	4
9,786,207	9,958,916	34,307	35,068	5
554,388	542,639	15,129	15,189	6
228,521	231,395	5	5	7
64,727	64,870	71	65	8
2,274	2,169	23	23	9
83,547,420	85,848,831	4,900,326	4,874,858	10
8,618,313	12,652,803	26	32	11
92,165,733	98,501,634	4,900,352	4,874,890	12
				13
92,165,733	98,501,634	4,900,352	4,874,890	14

Line 12, column (b) includes \$ 95,763,000 of unbilled revenues.
 Line 12, column (d) includes 456,000 MWH relating to unbilled revenues

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 300 Line No.: 10 Column: b
Includes recognized revenue of \$3,686,000 in the deferred revenue account.

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	NOTE: "@" Indicates Direct Acces					
2						
3	ACCOUNT 440					
4						
5	D-APS-N	3,009	363,145	485	6,204	0.1207
6	D-APS	445,570	68,024,143	50,721	8,785	0.1527
7	D-APS @	2,914	273,870	296	9,845	0.0940
8	D-APSE-N	11,118	1,156,493	1,824	6,095	0.1040
9	D-APSE	1,636,435	236,893,506	186,809	8,760	0.1448
10	D-APSE @	7,125	589,930	781	9,123	0.0828
11	D-CARE-APS-N	202	17,439	25	8,080	0.0863
12	D-CARE-APS	104,940	10,167,526	13,975	7,509	0.0969
13	D-CARE-APS @	414	11,652	56	7,393	0.0281
14	D-CARE-N	3,308	300,326	520	6,362	0.0908
15	D-CARE	6,948,153	706,784,875	1,192,275	5,828	0.1017
16	D-CARE @	7,086	293,331	1,172	6,046	0.0414
17	D-FERA-APS-E	23,820	3,115,296	2,459	9,687	0.1308
18	D-FERA-APS-N	9	968	1	9,000	0.1076
19	D-FERA-APS	3,197	443,713	331	9,659	0.1388
20	D-FERA-APSE-N		749	2		
21	D-FERA-N	195	36,926	21	9,286	0.1894
22	D-FERA	157,480	21,753,294	20,892	7,538	0.1381
23	D-N	66,269	9,137,190	9,834	6,739	0.1379
24	D-PG-S	7	1,092	1	7,000	0.1560
25	D-S-CARE-N	26	2,263	2	13,000	0.0870
26	D-S-CARE	5,265	543,627	512	10,283	0.1033
27	D-S-CARE @	41	2,107	4	10,250	0.0514
28	D-S-FERA	155	21,063	13	11,923	0.1359
29	D-S-N	539	63,031	59	9,136	0.1169
30	D-S	53,734	8,521,968	4,888	10,993	0.1586
31	D-S @	338	33,999	27	12,519	0.1006
32	D-TOU-1-APSE	191	25,102	22	8,682	0.1314
33	D-TOU-1-CPP-N	3	10	1	3,000	0.0033
34	D-TOU-1-N	2,622	160,649	322	8,143	0.0613
35	D-TOU-1	1,627	238,388	200	8,135	0.1465
36	D-TOU-1 @	13	1,195	1	13,000	0.0919
37	D-TOU-2-APS	261	40,097	16	16,313	0.1536
38	D-TOU-2-APSE	4,694	675,772	301	15,595	0.1440
39						
40						
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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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	ACCOUNT 440 CONTINUED					
2						
3	D-TOU-2-N	3,706	330,178	260	14,254	0.0891
4	D-TOU-2	39,537	6,309,761	2,240	17,650	0.1596
5	D-TOU-2 @	35	3,611	3	11,667	0.1032
6	D-TOU-EV-1	142	15,932	70	2,029	0.1122
7	D-TOU-CARE-N	48	2,899	6	8,000	0.0604
8	D-TOU1-CARE	144	15,552	17	8,471	0.1080
9	D-TOU2-CARE	2,069	256,929	152	13,612	0.1242
10	D-TOU2-CARE@	7	485	1	7,000	0.0693
11	D-TOUT-APS-N	116	4,266	14	8,286	0.0368
12	D-TOUT-APS	15	2,279	1	15,000	0.1519
13	D-TOUT-APSE-N	830	20,797	90	9,222	0.0251
14	D-TOUT-APSE	244	39,857	20	12,200	0.1633
15	D-TOUT-C-APS	1	101	1	1,000	0.1010
16	D-TOUT-C-APSE	3	384	1	3,000	0.1280
17	D-TOUT-CARE-N	41	980	4	10,250	0.0239
18	D-TOUT-CARE	108	16,212	7	15,429	0.1501
19	D-TOUT-N	3,317	190,987	335	9,901	0.0576
20	D-TOUT	1,534	314,736	86	17,837	0.2052
21	D-TOUTCAPSE-N	28	852	2	14,000	0.0304
22	D-TU1-C-APS	6	647	1	6,000	0.1078
23	D-TU1-C-APSE	27	3,036	3	9,000	0.1124
24	D-TU2-C-APS	40	5,201	2	20,000	0.1300
25	D-TU2-C-APSE	325	35,811	25	13,000	0.1102
26	D	17,487,934	2,778,914,349	2,625,977	6,660	0.1589
27	D @	44,436	4,741,876	5,129	8,664	0.1067
28	DCARE-APSE-N	705	53,694	101	6,980	0.0762
29	DCARE-APSE	552,237	50,888,863	68,896	8,016	0.0922
30	DCARE-APSE @	1,293	34,603	161	8,031	0.0268
31	DCARE-E-APS	45	5,617	3	15,000	0.1248
32	DCARE-E	3,356	414,317	353	9,507	0.1235
33	DE-APS-N	18	1,602	4	4,500	0.0890
34	DE-APS	9,990	1,112,369	1,072	9,319	0.1113
35	DE-APSE-N	54	4,343	11	4,909	0.0804
36	DE-APSE	29,980	3,164,419	3,286	9,124	0.1056
37	DE-CPP	8	900	1	8,000	0.1125
38	DE-FERA-APS-E	193	18,862	19	10,158	0.0977
39	DE-FERA-APS	50	5,893	4	12,500	0.1179
40	DE-FERA-S	3	235			0.0783
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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1	ACCOUNT 440 CONTINUED					
2						
3	DE-FERA	441	45,858	49	9,000	0.1040
4	DE-N	87	7,541	17	5,118	0.0867
5	DE-S	258	29,521	20	12,900	0.1144
6	DE-TOU-1-N	5	154	1	5,000	0.0308
7	DE-TOU-2	458	52,209	29	15,793	0.1140
8	DE-TOU1-APS	8	926	1	8,000	0.1158
9	DE-TOU1-APSE	14	957	3	4,667	0.0684
10	DE-TOU2-APS	67	7,258	4	16,750	0.1083
11	DE-TOU2-APSE	189	20,318	15	12,600	0.1075
12	DE-TOUT-APS-N	7	5	1	7,000	0.0007
13	DE-TOUT-APSE	12	824	1	12,000	0.0687
14	DE-TOUT	9	1,106	1	9,000	0.1229
15	DE-TUTEV-N	1	1			0.0010
16	DE	87,006	10,035,058	11,026	7,891	0.1153
17	DE @	19	1,234	2	9,500	0.0649
18	DETU2APSE-CPP	5	435			0.0870
19	DM-CARE-E	21	2,715	2	10,500	0.1293
20	DM-CARE		-24			
21	DM-N	268	32,916	28	9,571	0.1228
22	DM	94,630	15,419,610	6,005	15,759	0.1629
23	DM @	1,149	108,058	40	28,725	0.0940
24	DMS-1	37,660	4,507,769	254	148,268	0.1197
25	DMS-1 @	10	681	1	10,000	0.0681
26	DMS-2-N	114	1,430	1	114,000	0.0125
27	DMS-2	497,907	47,382,915	1,521	327,355	0.0952
28	DMS-2 @	1,583	76,591	8	197,875	0.0484
29	DMS-3	15,318	1,909,198	59	259,627	0.1246
30	DMS-3 @	222	12,944	1	222,000	0.0583
31	DTU-TEV-N	17	25	3	5,667	0.0015
32	DTU-TEV	46	8,317	4	11,500	0.1808
33	DTU2-CARE-N		-6,258	1		
34	DWL-A	2,297	751,412	95	24,179	0.3271
35	DWL-A @	16	4,617	1	16,000	0.2886
36	DWL-B	50	8,976	1	50,000	0.1795
37	DWL-C	101	20,181	3	33,667	0.1998
38	GS-1-APS	18	2,763	2	9,000	0.1535
39	GS-1-CARE	158	16,967	11	14,364	0.1074
40	GS-1-N	104	14,112	17	6,118	0.1357
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
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1	ACCOUNT 440 CONTINUED					
2						
3	GS-1	288,838	52,118,518	55,209	5,232	0.1804
4	GS-1 @	1,897	201,508	226	8,394	0.1062
5	GS-2-APS	306	36,644	1	306,000	0.1198
6	GS-2-N	164	22,467	1	164,000	0.1370
7	GS-2	99,773	14,372,923	1,590	62,750	0.1441
8	GS-2 @	3,214	209,206	35	91,829	0.0651
9	GS1-APSE	241	34,167	23	10,478	0.1418
10	GS2-APSE	3	442			0.1473
11	GS2-TOU-B-S	644	76,264	1	644,000	0.1184
12	GS2/1BL-APSE	36	7,000	1	36,000	0.1944
13	LS-1-ALLNITE		12			
14	OL-1-ALLNITE	2,757	649,154	3,714	742	0.2355
15	OL-1-ALLNITE @	1	105	1	1,000	0.1050
16	PA-1	608	160,389	135	4,504	0.2638
17	PA-2	262	39,288	4	65,500	0.1500
18	TOU-GS-1-N	21	739	2	10,500	0.0352
19	TOU-GS-1	4,965	638,089	320	15,516	0.1285
20	TOU-GS-1 @	164	19,114	33	4,970	0.1165
21	TOU-GS3-B-P	-174	-13,480			0.0775
22	TOU-PA-A	33	4,678	1	33,000	0.1418
23	TOU-PA-B	142	14,443	2	71,000	0.1017
24	TOU-PA-SOP-2	1	629			0.6290
25	TOUPA-B-I-API	69	10,083	1	69,000	0.1461
26						
27						
28						
29	OTHER ADJUSTMENTS		52,593			
30						
31	TOTAL ACCOUNT 440	28,817,625	4,065,762,465	4,277,734	6,737	0.1411
32						
33	ACCOUNT 442					
34						
35	AL-2-A	145,023	9,147,082	7,447	19,474	0.0631
36	AL-2-A @	3,529	138,738	45	78,422	0.0393
37	AL-2-B	1,242	81,179	33	37,636	0.0654
38	AL-2-B @	12	372			0.0310
39	AL-2	148	7,878			0.0532
40	G2TA/1BL-APSE	9	1,934			0.2149
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
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1	ACCOUNT 442 CONTINUED					
2						
3	G2TB/1BL-APSE	337	58,456	1	337,000	0.1735
4	GS-1-APS-C	40	4,068	2	20,000	0.1017
5	GS-1-APS	13,826	2,022,706	924	14,963	0.1463
6	GS-1-APS @	168	14,679	12	14,000	0.0874
7	GS-1-CARE	1,206	126,414	56	21,536	0.1048
8	GS-1-CPP	25	2,887	1	25,000	0.1155
9	GS-1-G-S		-10,013	1		
10	GS-1-N	4,203	412,414	299	14,057	0.0981
11	GS-1	4,122,562	654,255,588	401,831	10,259	0.1587
12	GS-1 @	28,295	2,933,303	3,102	9,122	0.1037
13	GS-2-APS-C	91	9,259	1	91,000	0.1017
14	GS-2-APS-N	993	169,785	8	124,125	0.1710
15	GS-2-APS	120,713	19,630,472	1,132	106,637	0.1626
16	GS-2-APS @	17,799	946,191	73	243,822	0.0532
17	GS-2-CARE	11,310	1,105,614	70	161,571	0.0978
18	GS-2-CPP-N	35	4,642			0.1326
19	GS-2-CPP	370	16,302	2	185,000	0.0441
20	GS-2-N	35,418	5,062,126	279	126,946	0.1429
21	GS-2-S	8,452	1,144,343	35	241,486	0.1354
22	GS-2-S @	621	21,890	1	621,000	0.0352
23	GS-2	12,370,202	1,762,793,239	106,760	115,869	0.1425
24	GS-2 #		13,950			
25	GS-2 @	722,309	38,239,968	2,535	284,935	0.0529
26	GS-TOU-EV-3	181	31,419	14	12,929	0.1736
27	GS-TOU-EV-4	1,517	298,942	21	72,238	0.1971
28	GS1-APSE-N	279	23,497	15	18,600	0.0842
29	GS1-APSE	53,711	7,497,664	3,755	14,304	0.1396
30	GS1-APSE @	564	43,361	35	16,114	0.0769
31	GS1-C-APSE	37	3,343	1	37,000	0.0904
32	GS2-APSE-CPP	213	45,695	1	213,000	0.2145
33	GS2-APSE	327,381	48,340,002	2,579	126,941	0.1477
34	GS2-APSE @	92,506	4,283,117	337	274,499	0.0463
35	GS2-C-APSE	770	78,370	6	128,333	0.1018
36	GS2-TOU-A-P	939	127,213	4	234,750	0.1355
37	GS2-TOU-A-S-N	1,839	257,805	15	122,600	0.1402
38	GS2-TOU-A-S	66,130	11,154,600	465	142,215	0.1687
39	GS2-TOU-A-S @	19	5,795	1	19,000	0.3050
40	GS2-TOU-A-T	99	10,592	1	99,000	0.1070
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
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1	ACCOUNT 442 CONTINUED					
2						
3	GS2-TOU-B-DL#		232			
4	GS2-TOU-B-EDW	609	77,494	5	121,800	0.1272
5	GS2-TOU-B-P	2,119	258,097	11	192,636	0.1218
6	GS2-TOU-B-P @	251	15,465	1	251,000	0.0616
7	GS2-TOU-B-S-N	4,417	496,316	20	220,850	0.1124
8	GS2-TOU-B-S	708,202	84,795,765	2,872	246,588	0.1197
9	GS2-TOU-B-S @	294,372	15,144,671	1,081	272,315	0.0514
10	GS2-TOU-S-B	-726	-429,889	7	-103,714	0.5921
11	GS2-TUB-CPP-P	2,032	239,763	5	406,400	0.1180
12	GS2-TUB-CPP-S	94,535	12,476,570	177	534,096	0.1320
13	GS2-TUB-CPP-T	157	21,916	1	157,000	0.1396
14	GS2/1BL-APSE	52,888	8,553,317	678	78,006	0.1617
15	GS2/1BL-APSE@	2,171	116,018	9	241,222	0.0534
16	GS2/1BLC-APSE	37	4,757	1	37,000	0.1286
17	GS2T-A-APS	2,517	444,130	26	96,808	0.1765
18	GS2T-A-APSE-N	49	10,139	1	49,000	0.2069
19	GS2T-A-APSE	26,458	4,342,639	336	78,744	0.1641
20	GS2T-A-CPP-S	19	2,819			0.1484
21	GS2T-B-APS	8,701	1,473,311	86	101,174	0.1693
22	GS2T-B-APS @	726	47,267	2	363,000	0.0651
23	GS2T-B-APSE	53,456	5,959,891	140	381,829	0.1115
24	GS2T-B-APSE @	29,467	1,468,800	67	439,806	0.0498
25	GS2T-B-CARE	413	38,440	1	413,000	0.0931
26	GS2TBAPSE-CPP	598	101,868	2	299,000	0.1703
27	GS2TOU-A/1BL	1,341	288,699	18	74,500	0.2153
28	GS2TOU-B/1BL	3,965	524,139	11	360,455	0.1322
29	GS2TOU-R-N-S	2,659	274,045	23	115,609	0.1031
30	GS2TOU-R-S	9	1,799	2	4,500	0.1999
31	GS2TOU-R-S @	181	15,739	2	90,500	0.0870
32	GS2TRN-APSE-S	171	17,676	4	42,750	0.1034
33	GS2TUB-CPPN-S	47	4,551			0.0968
34	LS-1-ALLNITE	13,160	4,036,769	2,762	4,765	0.3067
35	LS1-MIDNITE	8	2,597	1	8,000	0.3246
36	LS-2-B	20	2,503	4	5,000	0.1252
37	LS-2	1,596	147,832	187	8,535	0.0926
38	LS-2 @	6	393	2	3,000	0.0655
39	LS-3	25,684	1,864,607	2,645	9,710	0.0726
40	LS-3 @	1,767	76,836	143	12,357	0.0435
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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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	ACCOUNT 442 CONTINUED					
2						
3	LS1-ALLNITE@	92	25,373	3	30,667	0.2758
4	LS1-TAP	118	42,255			0.3581
5	OL-1-ALLNITE	10,290	2,112,603	6,371	1,615	0.2053
6	OL-1ALLNITE@	76	11,240	27	2,815	0.1479
7	PA-1-API	-30	-4,085			0.1362
8	PA-1-I-API	1,447	199,467	17	85,118	0.1378
9	PA-1-N	363	49,662	24	15,125	0.1368
10	PA-1-SPEC-5	8,634	2,446,564	2,086	4,139	0.2834
11	PA-1-SPEC-5@		2,464	1		
12	PA-1	296,104	51,979,128	15,421	19,201	0.1755
13	PA-1 @	1,513	123,003	36	42,028	0.0813
14	PA-2-API	-165	-15,011			0.0910
15	PA-2-DL #		4,430			
16	PA-2-I-API	5,955	545,934	27	220,556	0.0917
17	PA-2-S	222	25,880	2	111,000	0.1166
18	PA-2	239,365	31,880,908	3,080	77,716	0.1332
19	PA-2 @	6,443	387,256	40	161,075	0.0601
20	RTP-2-DLS #		334,750			
21	RTP-2-P-BIP	41,324	4,737,824	7	5,903,429	0.1147
22	RTP-2-P	60,252	7,806,081	14	4,303,714	0.1296
23	RTP-2-P-BIP	66,204	7,590,820	25	2,648,160	0.1147
24	RTP-2-S-P	7,008	833,875	2	3,504,000	0.1190
25	RTP-2-S-S	1,341	206,275	1	1,341,000	0.1538
26	RTP-2-S-T	605,314	38,130,013	2	302,657,000	0.0630
27	RTP-2-S	46,026	6,753,090	31	1,484,710	0.1467
28	RTP-2-SGDR-T			1		
29	RTP-2-T-BIP	226,200	15,377,117	6	37,700,000	0.0680
30	RTP-2-S-T-BIP	11,365	1,156,842	1	11,365,000	0.1018
31	RTP-2-SGDR-T	153,203	9,925,933			0.0648
32	TC-1	58,360	8,272,578	13,536	4,311	0.1418
33	TC-1 @	1,637	158,024	342	4,787	0.0965
34	TG3BAPS-CPP-S	595	124,946	1	595,000	0.2100
35	TGS3-C-CPP-P	356	21,156			0.0594
36	TGS3-C-CPP-S	2,660	200,108	3	886,667	0.0752
37	TGS3-CPP-N-S	2,335	308,917	4	583,750	0.1323
38	TGS3-CPP-P	94,561	11,003,418	86	1,099,547	0.1164
39	TGS3-CPP-S	3,035,260	354,457,678	3,015	1,006,720	0.1168
40	TGS3-CPP-T	3,748	499,330	6	624,667	0.1332
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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1	ACCOUNT 442 CONTINUED					
2						
3	TGS3-R-N-P	1,408	161,750	2	704,000	0.1149
4	TGS3-R-N-S	13,639	1,575,727	25	545,560	0.1155
5	TGS3-R-S	280	84,394	1	280,000	0.3014
6	TGS3-R-S @	380	26,616	1	380,000	0.0700
7	TGS3CPP-BIP-S	-80	-10,292			0.1287
8	TOU-8-APS-S@		156			
9	TOU-8-CPP-S	15	1,303			0.0869
10	TOU-8-DL-S #		2,542,541			
11	TOU-8-P-CPP	-93	-7,031			0.0756
12	TOU-8-P	-51,174	-6,245,920			0.1221
13	TOU-8-P @	-10,432	-483,195			0.0463
14	TOU-8-S-BIP		13,603			
15	TOU-8-S-BIP@					
16	TOU-8-S-P	64,107	6,956,379			0.1085
17	TOU-8-S-S	13,438	1,501,813			0.1118
18	TOU-8-S-S @	1,245	75,441			0.0606
19	TOU-8-S-T	112,231	10,505,244	3	37,410,333	0.0936
20	TOU-8-S	-19,411	-1,871,583			0.0964
21	TOU-8-S @	10,432	503,252			0.0482
22	TOU-8-T-BIP@	1,584	-33,392			-0.0211
23	TOU-8-T	-112,343	-10,366,986	1	-112,343,000	0.0923
24	TOU-GS-1-APS	26	3,481	1	26,000	0.1339
25	TOU-GS-1-CPP	73	8,789	3	24,333	0.1204
26	TOU-GS-1-N	259	21,028	8	32,375	0.0812
27	TOU-GS-1	77,992	10,022,898	2,990	26,084	0.1285
28	TOU-GS-1- @	7,648	908,987	1,222	6,259	0.1189
29	TOU-GS-A-S	532,127	84,564,324	953	558,370	0.1589
30	TOU-GS-3-B-S	2,221,772	253,896,616	1,799	1,235,004	0.1143
31	TOU-GS1-APSE	70	8,496	6	11,667	0.1214
32	TOU-GS3-A-P-N	349	46,522	1	349,000	0.1333
33	TOU-GS3-A-P	17,584	2,496,215	23	764,522	0.1420
34	TOU-GS3-A-P @	765	41,715	1	765,000	0.0545
35	TOU-GS3-A-S-N	6,174	834,930	11	561,273	0.1352
36	TOU-GS3-A-S @	16,695	1,220,737	24	695,625	0.0731
37	TOU-GS3-B-P-N	2,326	228,700	2	1,163,000	0.0983
38	TOU-GS3-B-P	33,820	3,920,156	25	1,352,800	0.1159
39	TOU-GS3-B-P @	11,801	678,597	10	1,180,100	0.0575
40	TOU-GS3-B-S-N	34,174	4,035,943	39	876,256	0.1181
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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1	aACCOUNT 442 CONTINUED					
2						
3	TOU-GS3-B-S @	1,535,577	69,818,542	925	1,660,083	0.0455
4	TOU-GS3-B-T	4,785	275,391			0.0576
5	TOU-GS3-B-T @	2,638	99,278	2	1,319,000	0.0376
6	TOU-GS3A-S-S	4,034	528,274	4	1,008,500	0.1310
7	TOU-GS3A-S-S-@	365	24,852	1	365,000	0.0681
8	TOU-GS3B-C-P	699	73,002	1	699,000	0.1044
9	TOU-GS3B-C-S	8,390	668,934	9	932,222	0.0797
10	TOU-GS3B-EDW	666	61,648	1	666,000	0.0926
11	TOU-GS3B-S-P	4,159	606,913	7	594,143	0.1459
12	TOU-GS3B-S-S	27,350	3,156,553	24	1,139,583	0.1154
13	TOU-GS3B-S-S@	-1,294	-24,136	2	-647,000	0.0187
14	TOU-GS3B-S-T	3,120	636,149	2	1,560,000	0.2039
15	TOU-GS3SOP-S	10,425	1,546,713	14	744,643	0.1484
16	TOU-PA-5-N	901	72,339	2	450,500	0.0803
17	TOU-PA-5-S	1,170	124,347	2	585,000	0.1063
18	TOU-PA-5	336,580	28,506,502	514	654,825	0.0847
19	TOU-PA-5 @	2,818	169,581	4	704,500	0.0602
20	TOU-PA-A-N	221	16,305	1	221,000	0.0738
21	TOU-PA-A	197,294	21,580,978	1,185	166,493	0.1094
22	TOU-PA-A @	1,130	74,607	4	282,500	0.0660
23	TOU-PA-B-API	-52	-5,235			0.1007
24	TOU-PA-B-BIP	-169	-24,444			0.1446
25	TOU-PA-B-CPP	7,571	708,877	6	1,261,833	0.0936
26	TOU-PA-B-DL#		4,362			
27	TOU-PA-B-N	9,903	824,689	15	660,200	0.0833
28	TOU-PA-B-S	3,005	268,353	5	601,000	0.0893
29	TOU-PA-B	1,214,440	114,579,303	3,665	331,362	0.0943
30	TOU-PA-B @	47,108	2,525,213	67	703,104	0.0536
31	TOU-PA-ICE	36,253	2,948,263	225	161,124	0.0813
32	TOU-PA-RTP	1,413	122,307	3	471,000	0.0866
33	TOU-PA-SOP-1	131,543	12,569,578	683	192,596	0.0956
34	TOU-PA-SOP-2	66,231	6,239,273	213	310,944	0.0942
35	TOU-PA-SOP1-N	238	23,759	3	79,333	0.0998
36	TOU-PA-SOP1@	4,302	236,790	5	860,400	0.0550
37	TOU-PA-SOP2@	20	3,873	1	20,000	0.1937
38	TOU-PA5-I-API	36,386	2,507,795	47	774,170	0.0689
39	TOU8-CPP-N-P	13,608	1,306,240	3	4,536,000	0.0960
40	TOU8-CPP-N-S	8,393	981,621	4	2,098,250	0.1170
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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1	ACCOUNT 442 CONTINUED					
2						
3	TOU8-CPP-P	1,250,945	130,044,440	228	5,486,601	0.1040
4	TOU8-CPP-S-P	6,583	911,933	1	6,583,000	0.1385
5	TOU8-CPP-S-S	17,951	1,975,361	3	5,983,667	0.1100
6	TOU8-CPP-S	2,764,711	315,939,149	949	2,913,289	0.1143
7	TOU8-CPP-T	268,319	19,792,954	17	15,783,471	0.0738
8	TOU8-R-N-P	19,440	2,028,797	6	3,240,000	0.1044
9	TOU8-R-N-S	10,541	1,022,255	6	1,756,833	0.0970
10	TOU8-R-P	1,153	144,949	1	1,153,000	0.1257
11	TOU8-R-P @	7,312	338,646	1	7,312,000	0.0463
12	TOU8-R-S-P	2,155	209,630	1	2,155,000	0.0973
13	TOU8-R-S	11	3,078			0.2798
14	TOU8CPPGCCD-P	240	-959			-0.0040
15	TOU8CPPGCCD-S	17	1,809			0.1064
16	TOUG3A-APSE-P	2,342	307,359	3	780,667	0.1312
17	TOUG3A-APSE-S	115,494	17,704,786	260	444,208	0.1533
18	TOUG3B-APSE-P	6,018	680,766	6	1,003,000	0.1131
19	TOUG3B-APSE-S	161,027	21,433,075	215	748,963	0.1331
20	TOUG3BAPSE-S@	4,264	201,372	3	1,421,333	0.0472
21	TOUGS3A-CPP-S	-141	-17,449			0.1238
22	TOUGS3AAPS-S	36,012	5,964,190	79	455,848	0.1656
23	TOUGS3AS-BIP	24,048	3,413,837	42	572,571	0.1420
24	TOUGS3BAPS-P	5,941	700,286	5	1,188,200	0.1179
25	TOUGS3BAPS-S	70,607	9,687,652	100	706,070	0.1372
26	TOUGS3BAPS-S@	9,924	839,273	19	522,316	0.0846
27	TOUGS3BP-BIP	11,499	1,070,573	7	1,642,714	0.0931
28	TOUGS3BP-BIP@	198	15,560	1	198,000	0.0786
29	TOUGS3BP-CPP	-176	-21,169			0.1203
30	TOUGS3BS-BIP	128,227	12,670,959	94	1,364,117	0.0988
31	TOUGS3BS-BIP@	12,524	604,400	13	963,385	0.0483
32	TOUGS3BS-CPP	-5,358	-500,393	2	-2,679,000	0.0934
33	TOUGS3BT-BIP	197	25,762			0.1308
34	TOUPA-B-I-API	172,913	13,226,427	372	464,820	0.0765
35	TOUPA-ICE-API	4,598	282,067	26	176,846	0.0613
36	TOUPA5I-API-N	621	46,193	1	621,000	0.0744
37	TOUPABI-API-N	631	45,083	2	315,500	0.0714
38	TOUPASOP1-API	58,212	4,653,477	203	286,759	0.0799
39	TOUPASOP2-API	23,468	1,751,530	75	312,907	0.0746
40	TU8A-BIP-P	1,016	115,569			0.1137
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
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1	ACCOUNT 442 CONTINUED					
2						
3	TU8A-CPP-P	-304	-50,507			0.1661
4	TU8A-P	-711	-65,062			0.0915
5	TU8A-S-P			1		
6	TU8A-S	1,020	162,596	1	1,020,000	0.1594
7	TU8B-APS-P	22,727	2,874,082	9	2,525,222	0.1265
8	TU8B-APS-S	26,999	3,910,442	15	1,799,933	0.1448
9	TU8B-APS-S @	12,573	858,532	9	1,397,000	0.0683
10	TU8B-APSE-N-P	-117	-31,793			0.2717
11	TU8B-APSE-P	60,252	7,379,322	21	2,869,143	0.1225
12	TU8B-APSE-P @	19,044	786,056	2	9,522,000	0.0413
13	TU8B-APSE-S-P	6,147	960,155	3	2,049,000	0.1562
14	TU8B-APSE-S-S	1,265	209,655	1	1,265,000	0.1657
15	TU8B-APSE-S	170,429	21,490,495	68	2,506,309	0.1261
16	TU8B-APSE-S @	2,081	134,224	1	2,081,000	0.0645
17	TU8B-APSE-T	114,864	7,838,705	2	57,432,000	0.0682
18	TU8B-CPP-P	-33,083	-3,081,024			0.0931
19	TU8B-CPP-S	-20,630	-2,089,940			0.1013
20	TU8B-DL-S #		5,710,456			
21	TU8B-P-BIP-N	25,805	2,479,907	2	12,902,500	0.0961
22	TU8B-P-BIP	888,003	79,156,696	92	9,652,207	0.0891
23	TU8B-P-BIP @	304,571	8,662,383	22	13,844,136	0.0284
24	TU8B-P-N	258,555	26,623,818	18	14,364,167	0.1030
25	TU8B-P	1,653,840	173,696,810	210	7,875,429	0.1050
26	TU8B-P @	935,530	36,610,911	87	10,753,218	0.0391
27	TU8B-S-BIP-N	12,623	1,208,067	2	6,311,500	0.0957
28	TU8B-S-BIP	934,611	92,261,927	211	4,429,436	0.0987
29	TU8B-S-BIP @	180,454	5,772,559	37	4,877,135	0.0320
30	TU8B-S-CPP-P	-550	-63,621			0.1157
31	TU8B-S-N	152,142	16,751,902	41	3,710,780	0.1101
32	TU8B-S-P-BIP	35,843	4,270,066	6	5,973,833	0.1191
33	TU8B-S-P-BIP@	19,014	399,737	1	19,014,000	0.0210
34	TU8B-S-P	502,212	51,540,538	44	11,413,909	0.1026
35	TU8-S-P @	96,926	5,135,801	7	13,846,571	0.0530
36	TU8B-S-S-BIP	41,596	3,738,919	5	8,319,200	0.0899
37	TU8B-S-S-BIP@	8,918	259,623	2	4,459,000	0.0291
38	TU8B-S-S	142,485	16,257,008	39	3,653,462	0.1141
39	TU8B-S-S @	27,856	1,269,382	6	4,642,667	0.0456
40	TU8B-S-T-BIP	378,071	20,664,368	3	126,023,667	0.0547
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

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	ACCOUNT 442 CONTINUED					
2						
3	TU8B-S-T-BIP@	193,957	428,696	3	64,652,333	0.0022
4	TU8B-S-T	590,427	45,879,704	60	9,840,450	0.0777
5	TU8B-S-T @	127,067	3,693,019	9	14,118,556	0.0291
6	TU8B-S	2,854,110	329,100,156	853	3,345,967	0.1153
7	TU8B-S @	1,374,446	61,666,683	356	3,860,803	0.0449
8	TU8B-T-BIP-N	104,216	6,766,885	2	52,108,000	0.0649
9	TU8B-T-BIP	1,451,465	83,747,414	29	50,050,517	0.0577
10	TU8B-T-BIP @	537,021	4,413,436	8	67,127,625	0.0082
11	TU8B-T-N	268,693	19,866,603	4	67,173,250	0.0739
12	TU8B-T	1,381,336	96,946,436	28	49,333,429	0.0702
13	TU8B-T @	1,141,906	24,237,566	23	49,648,087	0.0212
14	TU8BAPSE-S-P@	812	36,642	1	812,000	0.0451
15	TU8BAPSE-S-S@	10,750	517,218	1	10,750,000	0.0481
16	TU8BAPSECPP-P	4,943	770,041	2	2,471,500	0.1558
17	TU8BAPSECPP-S	7,597	1,257,936	3	2,532,333	0.1656
18	TUG3AAPSE-S-S	880	118,812	1	880,000	0.1350
19	TUG3BAPSE-S-P	96	15,226			0.1586
20	TUG3BAPSE-S-S	728	108,542	1	728,000	0.1491
21	TUGBAPSECPPP	795	116,594	1	795,000	0.1467
22	TUG3BAPSECPPS	9,837	1,458,852	15	655,800	0.1483
23	TUG3BAPSESBIP	-97	-12,191			0.1257
24	TUGS3-A-S-DL#		2,345			
25	TUGS3-B-S-DL#	1	112,128			112.1280
26	TUG3BAPS-S-N	1,436	172,871	2	718,000	0.1204
27	TUGS3SOPS-BIP	2,089	259,673	2	1,044,500	0.1243
28						
29						
30						
31						
32						
33						
34	WIRETECHRATE	6,735	894,213			0.1328
35						
36	OTHER ADJUSTMENTS		2,355			
37						
38	TOTAL ACCOUNT 442	53,433,274	5,756,480,328	607,364	87,976	0.1077
39						
40						
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWh of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
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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	ACCOUNT 444					
2						
3	AL-2-A	96	6,131	6	16,000	0.0639
4	GS-1	1,337	223,125	181	7,387	0.1669
5	GS-2	791	90,946	4	197,750	0.1150
6	LS-1-ALLNITE	336,545	88,951,348	3,571	94,244	0.2643
7	LS-2-B	173	31,274	5	34,600	0.1808
8	LS-2	102,896	10,085,940	3,718	27,675	0.0980
9	LS-2 @	2,473	273,228	63	39,254	0.1105
10	LS-3	61,983	4,602,214	5,487	11,296	0.0742
11	LS-3 @	7,974	368,266	654	12,193	0.0462
12	LS1-ALLNITE@	3,033	639,474	11	275,727	0.2108
13	TC-1	5,974	851,477	1,412	4,231	0.1425
14	TC-1 @	86	8,429	16	5,375	0.0980
15	TOUB-P-BIP	21,638	1,688,879	1	21,638,000	0.0781
16						
17						
18						
19	OTHER ADJUSTMENTS		-6,012			
20						
21	TOTAL ACCOUNT 444	544,999	107,814,719	15,129	36,023	0.1978
22						
23	ACCOUNT 445					
24						
25	EDWARDS-AFB	181,994	3,720,741	3	60,664,667	0.0204
26	MARCH-AFB	45,773	2,627,703	1	45,773,000	0.0574
27	SEQUOIA	754	34,436	1	754,000	0.0457
28						
29	OTHER ADJUSTMENTS		-33,686			
30						
31	TOTAL ACCOUNT 445	228,521	6,349,194	5	45,704,200	0.0278
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	ACCOUNT 446					
2						
3	GS-1	184	31,337	27	6,815	0.1703
4	GS2-TOU-A-P	356	53,807	1	356,000	0.1511
5	TC-1	84	10,963	15	5,600	0.1305
6	TGS3-CPP-P	9,051	1,158,973	9	1,005,667	0.1280
7	TOU-GS3-A-P	2,151	296,151	3	717,000	0.1377
8	TOU8-CPP-P	52,901	6,159,646	16	3,306,313	0.1164
9						
10						
11						
12	OTHER ADJUSTMENTS					
13						
14	TOTAL ACCOUNT 446	64,727	7,710,877	71	911,648	0.1191
15						
16	ACCOUNT 448					
17						
18	GS-1-SCE	38	6,036	4	9,500	0.1588
19	GS-2-SCE	1,413	163,155	2	706,500	0.1155
20	PA-1-SCE	384	55,436	14	27,429	0.1444
21	PA-2-SCE	439	53,033	3	146,333	0.1208
22						
23	OTHER ADJUSTMENTS					
24						
25	TOTAL ACCOUNT 448	2,274	277,660	23	98,870	0.1221
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	83,091,420	9,944,395,243	4,900,326	16,956	0.1197
42	Total Unbilled Rev.(See Instr. 6)	456,000	95,763,000	0	0	0.2100
43	TOTAL	83,547,420	10,040,158,243	4,900,326	17,049	0.1202

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

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

This footnote applies to entire schedule: "@" Symbol represents Direct Access Rate Schedule.

Schedule Page: 304 Line No.: 20 Column: b

Less than 1 MWh.

Schedule Page: 304 Line No.: 20 Column: e

Less than 1 MWh.

Schedule Page: 304 Line No.: 20 Column: f

Less than 1 MWh.

Schedule Page: 304.1 Line No.: 40 Column: d

Less than 12 Months' Data.

Schedule Page: 304.1 Line No.: 40 Column: e

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 15 Column: d

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 15 Column: e

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 18 Column: d

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 18 Column: e

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 20 Column: b

Less than 1 MWh.

Schedule Page: 304.2 Line No.: 20 Column: d

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 20 Column: e

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 20 Column: f

Less than 12 Months' Data.

Schedule Page: 304.2 Line No.: 33 Column: b

Less than 1 MWh.

Schedule Page: 304.2 Line No.: 33 Column: e

Less than 1 MWh.

Schedule Page: 304.2 Line No.: 33 Column: f

Less than 1 MWh.

Schedule Page: 304.3 Line No.: 10 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 10 Column: e

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 13 Column: b

Less than 1 MWh.

Schedule Page: 304.3 Line No.: 13 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 13 Column: e

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 21 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 21 Column: e

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 24 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 24 Column: e

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 29 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, and other miscellaneous adjustments.

Schedule Page: 304.3 Line No.: 38 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 38 Column: e

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 39 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 39 Column: e

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 40 Column: d

Less than 12 Months' Data.

Schedule Page: 304.3 Line No.: 40 Column: e

Less than 12 Months' Data.

Schedule Page: 304.4 Line No.: 9 Column: b

Less than 1 MWh.

Schedule Page: 304.4 Line No.: 9 Column: e

Less than 1 MWh.

Schedule Page: 304.4 Line No.: 9 Column: f

Less than 1 MWh.

Schedule Page: 304.4 Line No.: 18 Column: d

Less than 12 Months' Data.

Schedule Page: 304.4 Line No.: 18 Column: e

Less than 12 Months' Data.

Schedule Page: 304.4 Line No.: 24 Column: b

Less than 1 MWh.

Schedule Page: 304.4 Line No.: 24 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.4 Line No.: 24 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.4 Line No.: 24 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.5 Line No.: 3 Column: b

Less than 1 MWh.

Schedule Page: 304.5 Line No.: 3 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.5 Line No.: 3 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.5 Line No.: 3 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.5 Line No.: 20 Column: d

Less than 12 Months' Data.

Schedule Page: 304.5 Line No.: 20 Column: e

Less than 12 Months' Data.

Schedule Page: 304.5 Line No.: 33 Column: d

Less than 12 Months' Data.

Schedule Page: 304.5 Line No.: 33 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 4 Column: d

Less than 12 Months' Data.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 304.6 Line No.: 4 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 7 Column: d

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 7 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 11 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 11 Column: e

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 14 Column: d

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 14 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 15 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 15 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 15 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 15 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 20 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 20 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 20 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 20 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.6 Line No.: 28 Column: b

Less than 1 MWh.

Schedule Page: 304.6 Line No.: 28 Column: c

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 28 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 28 Column: f

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 31 Column: d

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 31 Column: e

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 35 Column: d

Less than 12 Months' Data.

Schedule Page: 304.6 Line No.: 35 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 7 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 7 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 8 Column: b

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 8 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 8 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 8 Column: f

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 9 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 9 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 10 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 10 Column: d

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.7 Line No.: 10 Column: e

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.7 Line No.: 10 Column: f

Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.7 Line No.: 11 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 11 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 12 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 12 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 13 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 13 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 14 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 14 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 14 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 14 Column: f

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 15 Column: b

Less than 1 MWh.

Schedule Page: 304.7 Line No.: 15 Column: c

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 15 Column: d

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 15 Column: e

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 15 Column: f

Less than 12 Months' Data.

Schedule Page: 304.7 Line No.: 16 Column: d

Less than 12 Months' Data.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 304.7 Line No.: 16 Column: e Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 17 Column: d Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 17 Column: e Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 18 Column: d Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 18 Column: e Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 20 Column: d Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 20 Column: e Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 21 Column: d Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 21 Column: e Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 22 Column: d Less than 12 Months' Data.
Schedule Page: 304.7 Line No.: 22 Column: e Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 4 Column: d Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 4 Column: e Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 23 Column: d Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 23 Column: e Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 24 Column: d Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 24 Column: e Less than 12 Months' Data.
Schedule Page: 304.8 Line No.: 26 Column: b Less than 1 MWh.
Schedule Page: 304.8 Line No.: 26 Column: d Data relected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 26 Column: e Data relected under parent rate schedule or other applicable tariff.
Schedule Page: 304.8 Line No.: 26 Column: f Data relected under parent rate schedule or other applicable tariff.
Schedule Page: 304.9 Line No.: 13 Column: d Less than 12 Months' Data.
Schedule Page: 304.9 Line No.: 13 Column: e Less than 12 Months' Data.
Schedule Page: 304.9 Line No.: 14 Column: d Less than 12 Months' Data.
Schedule Page: 304.9 Line No.: 14 Column: e Less than 12 Months' Data.
Schedule Page: 304.9 Line No.: 15 Column: d

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 15 Column: e

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 21 Column: d

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 21 Column: e

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 29 Column: d

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 29 Column: e

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 33 Column: d

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 33 Column: e

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 40 Column: d

Less than 12 Months' Data.

Schedule Page: 304.9 Line No.: 40 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 3 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 3 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 4 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 4 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 5 Column: b

Less than 1 MWh.

Schedule Page: 304.10 Line No.: 5 Column: c

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 5 Column: e

Less than 1 MWh.

Schedule Page: 304.10 Line No.: 5 Column: f

Less than 1 MWh.

Schedule Page: 304.10 Line No.: 10 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 10 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 18 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 18 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 19 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 19 Column: e

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 20 Column: b

Less than 1 MWh.

Schedule Page: 304.10 Line No.: 20 Column: d

Data relected under parent rate schedule or other applicable tariff.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 304.10 Line No.: 20 Column: e

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.10 Line No.: 20 Column: f

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.10 Line No.: 30 Column: d

Less than 12 Months' Data.

Schedule Page: 304.10 Line No.: 30 Column: e

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 19 Column: d

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 19 Column: e

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 23 Column: d

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 23 Column: e

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 24 Column: b

Less than 1 MWh.

Schedule Page: 304.11 Line No.: 24 Column: d

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.11 Line No.: 24 Column: e

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.11 Line No.: 24 Column: f

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.11 Line No.: 25 Column: d

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.11 Line No.: 25 Column: e

Data relected under parent rate schedule or other applicable tariff.

Schedule Page: 304.11 Line No.: 34 Column: d

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 34 Column: e

Less than 12 Months' Data.

Schedule Page: 304.11 Line No.: 36 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, and other miscellaneous adjustments.

Schedule Page: 304.12 Line No.: 19 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, and other miscellaneous adjustments.

Schedule Page: 304.12 Line No.: 29 Column: a

Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, and other miscellaneous adjustments.

Schedule Page: 304.13 Line No.: 12 Column: a

Footnote Linked. See note on 304.12, Row: 29, col/item:

Schedule Page: 304.13 Line No.: 23 Column: a

Footnote Linked. See note on 304.12, Row: 29, col/item:

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 not 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 long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Snohomish County Public Utility Distri1	SF	WSPP-2			
2	Tacoma Power	SF	WSPP-2			
3	TransAlta Energy Marketing (US), Inc.	SF	WSPP-2			
4	WAPA-WASN-Western Area Sierra NV Rgn	SF	FERC Vol. 8			
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	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, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
4,515,088		38,981,875		38,981,875	1
13,472		396,015		396,015	2
610		20,380		20,380	3
123,999		4,824,936		4,824,936	4
29,800		1,449,472		1,449,472	5
24,437		814,827		814,827	6
42,800		1,914,572		1,914,572	7
15,457		509,177		509,177	8
57,204		1,961,992		1,961,992	9
30		1,140		1,140	10
13,000		464,808		464,808	11
800		27,200		27,200	12
787,020		28,915,495		28,915,495	13
38,400		1,169,060		1,169,060	14
0	0	0	0	0	
8,618,313	0	176,835,806	0	176,835,806	
8,618,313	0	176,835,806	0	176,835,806	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)

demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
452,568		16,543,986		16,543,986	1
7		21		21	2
-5,400		-299,188		-299,188	3
36,029		1,136,024		1,136,024	4
125,063		4,130,784		4,130,784	5
2,025		82,364		82,364	6
50,430		1,814,784		1,814,784	7
263,241		7,411,428		7,411,428	8
22,000		801,960		801,960	9
125,788		4,444,312		4,444,312	10
690,253		25,305,944		25,305,944	11
400		18,900		18,900	12
800		25,940		25,940	13
7,000		196,250		196,250	14
0	0	0	0	0	
8,618,313	0	176,835,806	0	176,835,806	
8,618,313	0	176,835,806	0	176,835,806	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
40,521		1,309,144		1,309,144	1
8,800		257,200		257,200	2
13,239		396,766		396,766	3
436,156		9,243,438		9,243,438	4
36,400		1,034,980		1,034,980	5
13,647		434,069		434,069	6
9,998		383,804		383,804	7
110,354		3,345,551		3,345,551	8
3,840		109,939		109,939	9
4,562		153,508		153,508	10
10,768		270,361		270,361	11
161,033		5,977,413		5,977,413	12
65,200		2,094,684		2,094,684	13
210,259		6,502,222		6,502,222	14
0	0	0	0	0	
8,618,313	0	176,835,806	0	176,835,806	
8,618,313	0	176,835,806	0	176,835,806	

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401, line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
408		12,884		12,884	1
4					2
60,403		2,231,583		2,231,583	3
400		13,802		13,802	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
8,618,313	0	176,835,806	0	176,835,806	
8,618,313	0	176,835,806	0	176,835,806	

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	3,282,115	2,630,191
5	(501) Fuel	77,749,032	92,608,968
6	(502) Steam Expenses	8,451,256	8,984,804
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	816,354	895,472
10	(506) Miscellaneous Steam Power Expenses	5,811,774	5,801,182
11	(507) Rents	158,735	186,972
12	(509) Allowances	952,252	714,596
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	97,221,518	111,822,185
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,248,646	1,009,155
16	(511) Maintenance of Structures	1,035,540	1,481,561
17	(512) Maintenance of Boiler Plant	14,667,450	12,269,074
18	(513) Maintenance of Electric Plant	6,937,188	1,723,637
19	(514) Maintenance of Miscellaneous Steam Plant	4,139,859	4,084,022
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	28,028,683	20,567,449
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	125,250,201	132,389,634
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	70,963,242	84,916,350
25	(518) Fuel	87,057,636	94,150,781
26	(519) Coolants and Water	54,615	96,023
27	(520) Steam Expenses	33,070,198	37,471,803
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	13,067,891	9,344,405
31	(524) Miscellaneous Nuclear Power Expenses	147,787,426	128,712,266
32	(525) Rents	1,792,444	-3,285,041
33	TOTAL Operation (Enter Total of lines 24 thru 32)	353,793,452	351,406,587
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	47,911,631	49,930,279
36	(529) Maintenance of Structures	10,154,385	10,988,841
37	(530) Maintenance of Reactor Plant Equipment	42,815,006	33,267,365
38	(531) Maintenance of Electric Plant	43,266,867	31,871,053
39	(532) Maintenance of Miscellaneous Nuclear Plant	42,911,266	43,034,863
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	187,059,155	169,092,401
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	540,852,607	520,498,988
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	7,247,039	6,065,966
45	(536) Water for Power	4,029,271	4,025,782
46	(537) Hydraulic Expenses	3,091,969	2,713,725
47	(538) Electric Expenses	3,066,874	2,782,672
48	(539) Miscellaneous Hydraulic Power Generation Expenses	17,495,264	14,712,175
49	(540) Rents	2,135,487	1,742,541
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	37,065,904	32,042,861
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	2,727,094	2,147,472
54	(542) Maintenance of Structures	1,943,723	1,318,437
55	(543) Maintenance of Reservoirs, Dams, and Waterways	3,233,785	3,114,132
56	(544) Maintenance of Electric Plant	4,206,092	4,623,320
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,009,896	3,488,749
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	15,120,590	14,692,110
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	52,186,494	46,734,971

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	4,598,789	2,795,097
63	(547) Fuel	202,020,536	93,796,168
64	(548) Generation Expenses	5,453,822	3,762,693
65	(549) Miscellaneous Other Power Generation Expenses	16,221,886	8,578,198
66	(550) Rents	-439,890	361,024
67	TOTAL Operation (Enter Total of lines 62 thru 66)	227,855,143	109,293,180
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,581,322	1,693,915
70	(552) Maintenance of Structures	2,937,319	900,015
71	(553) Maintenance of Generating and Electric Plant	21,715,920	29,723,053
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,638,013	1,271,986
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	27,872,574	33,588,969
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	255,727,717	142,882,149
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	2,910,762,025	2,793,313,230
77	(556) System Control and Load Dispatching	1,799,700	1,209,588
78	(557) Other Expenses	16,300	12,618,449
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	2,912,578,025	2,807,141,267
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	3,886,595,044	3,649,647,009
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	14,120,253	18,444,567
84	(561) Load Dispatching	225,032	125,506
85	(561.1) Load Dispatch-Reliability	415,118	232,951
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	5,151,513	5,193,822
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	45,524,451	41,055,161
89	(561.5) Reliability, Planning and Standards Development	4,661,931	4,334,938
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	21,289,083	22,943,936
94	(563) Overhead Lines Expenses	4,023,331	3,366,437
95	(564) Underground Lines Expenses	963,316	894,427
96	(565) Transmission of Electricity by Others	16,640,479	9,409,691
97	(566) Miscellaneous Transmission Expenses	58,041,772	63,330,984
98	(567) Rents	7,505,002	6,446,949
99	TOTAL Operation (Enter Total of lines 83 thru 98)	178,561,281	175,779,369
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,741,719	3,154,982
102	(569) Maintenance of Structures	546,730	690,803
103	(569.1) Maintenance of Computer Hardware	4,236,525	3,540,510
104	(569.2) Maintenance of Computer Software	7,723,075	6,121,576
105	(569.3) Maintenance of Communication Equipment	2,129,282	1,661,007
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	15,275,553	10,091,442
108	(571) Maintenance of Overhead Lines	39,491,143	35,474,008
109	(572) Maintenance of Underground Lines	-141,403	474,282
110	(573) Maintenance of Miscellaneous Transmission Plant	1,559,364	1,543,716
111	TOTAL Maintenance (Total of lines 101 thru 110)	73,561,988	62,752,326
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	252,123,269	238,531,695

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	8,317,189	16,230,843
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	8,317,189	16,230,843
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)	8,317,189	16,230,843
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	38,413,964	34,244,118
135	(581) Load Dispatching		
136	(582) Station Expenses	29,806,538	25,235,032
137	(583) Overhead Line Expenses	23,655,642	29,352,555
138	(584) Underground Line Expenses	3,611,457	2,412,061
139	(585) Street Lighting and Signal System Expenses	480,008	93,188
140	(586) Meter Expenses	31,153,770	26,796,906
141	(587) Customer Installations Expenses	27,256,841	24,712,783
142	(588) Miscellaneous Expenses	113,478,505	96,457,363
143	(589) Rents	1,050,918	957,230
144	TOTAL Operation (Enter Total of lines 134 thru 143)	268,907,643	240,261,236
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,734,266	1,499,255
147	(591) Maintenance of Structures	186,056	71,507
148	(592) Maintenance of Station Equipment	7,817,602	8,322,730
149	(593) Maintenance of Overhead Lines	104,489,007	84,521,495
150	(594) Maintenance of Underground Lines	48,745,445	47,195,964
151	(595) Maintenance of Line Transformers	4,818,710	4,402,374
152	(596) Maintenance of Street Lighting and Signal Systems	6,287,812	7,731,661
153	(597) Maintenance of Meters	1,930,702	2,186,485
154	(598) Maintenance of Miscellaneous Distribution Plant	10,014,795	20,801,041
155	TOTAL Maintenance (Total of lines 146 thru 154)	187,024,395	176,732,512
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	455,932,038	416,993,748
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	19,673,367	13,015,140
160	(902) Meter Reading Expenses	39,194,001	43,625,638
161	(903) Customer Records and Collection Expenses	113,422,943	107,370,730
162	(904) Uncollectible Accounts	27,021,594	28,750,650
163	(905) Miscellaneous Customer Accounts Expenses	13,666,921	15,157,253
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	212,978,826	207,919,411

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	65,471,025	55,879,854
168	(908) Customer Assistance Expenses	503,138,231	416,881,076
169	(909) Informational and Instructional Expenses	17,548,715	17,805,582
170	(910) Miscellaneous Customer Service and Informational Expenses	9,841,709	-1,175,558
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	595,999,680	489,390,954
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		-1,471,667
175	(912) Demonstrating and Selling Expenses	3,597,175	6,757,087
176	(913) Advertising Expenses	8,993,938	7,958,650
177	(916) Miscellaneous Sales Expenses	1,212,700	1,458,096
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	13,803,813	14,702,166
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	518,112,367	434,164,315
182	(921) Office Supplies and Expenses	157,316,945	163,791,293
183	(Less) (922) Administrative Expenses Transferred-Credit	118,317,094	104,834,281
184	(923) Outside Services Employed	59,636,851	74,948,614
185	(924) Property Insurance	15,199,255	10,557,447
186	(925) Injuries and Damages	74,691,620	77,611,100
187	(926) Employee Pensions and Benefits	234,543,869	267,317,532
188	(927) Franchise Requirements	104,645,264	99,510,367
189	(928) Regulatory Commission Expenses	16,887,995	13,773,526
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	295,701	468,296
192	(930.2) Miscellaneous General Expenses	14,691,509	-4,268,929
193	(931) Rents	16,386,135	12,654,546
194	TOTAL Operation (Enter Total of lines 181 thru 193)	1,094,090,417	1,045,693,826
195	Maintenance		
196	(935) Maintenance of General Plant	13,731,598	11,284,133
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	1,107,822,015	1,056,977,959
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	6,533,571,874	6,090,393,785

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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	NON ASSOCIATED UTILITIES:					
2	SIERRA PACIFIC - FRINGE	OS		N/A		
3	UNITED STATES DEPARTMENT OF THE	OS		N/A		
4	INTERIOR - BUREAU INDIAN AFFAIRS					
5						
6	COOPERATIVES:					
7	VALLEY ELECTRIC ASSOCIATION, INC.	RQ	218	N/A	N/A	N/A
8						
9	MUNICIPALITIES:					
10	ANAHEIM, CITY OF FRINGE	OS		N/A		
11	BANNING, CITY OF FRINGE	OS		N/A		
12	L A DEPT OF WTR & PWR FRINGE	OS		N/A		
13	RIVERSIDE, CITY OF FRINGE	OS		N/A		
14						
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	OTHER PUBLIC AUTHORITIES:					
2	Department of Energy - Hoover SCE	LF	333	313.28	203.09	110.2
3	U.S. DEPT OF THE INTERIOR-BUREAU OF	OS		N/A		
4	RECLAMATION					
5	WAPA-WASN-Western Area Sierra Nev Reg	OS		N/A		
6	Metropolitan Water District- Exch Engy	EX	203	N/A	N/A	N/A
7	MWD 1987 Benefit Energy-Exch Engy	EX	203	N/A	N/A	N/A
8	PASADENA, CITY OF - EXCH ENGY	EX	317	N/A	N/A	N/A
9	LA Dept of Water & Pwr - Rtnd Engy			N/A		
10						
11	NEW BILATERAL DETAIL:					
12	CITIGROUP ENERGY INC.	SF	FERC Vol. 8	N/A		
13	DB ENERGY TRADING LLC	SF	FERC Vol. 8	N/A		
14	SEMPRA GENERATION	SF	FERC Vol. 8	N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1						
2	Non-Associated Utilities:					
3	ARIZONA PUBLIC SERVICE CO	SF	WSPP-2	N/A		
4	NEXTERA ENERGY PWR MRKT LLC	SF	WSPP-2	N/A		
5	PACIFIC GAS & ELECTRIC COMPANY	SF	WSPP-2	N/A		
6	PACIFICORP	SF	FERC Vol. 8	N/A		
7	PORTLAND GENERAL ELECTRIC	SF	FERC Vol. 8	N/A		
8	PUBLIC SERVICE CO. OF NEW MEXICO	SF	WSPP-2	N/A		
9	PUGET SOUND ENEGRGY, INC	SF	WSPP-2	N/A		
10	SAN DIEGO GAS & ELECTRIC	SF	WSPP-2	N/A		
11	SIERRA PACIFIC POWER CO.	SF	904.14.0	N/A		
12						
13	GAS					
14	CHEVRON NATURAL GAS	SF	FERC Vol. 8	N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ENSERCO ENERGY, INC.	SF	FERC Vol. 8	N/A		
2	KERN RIVER GAS TRANSMISSION CO	SF	FERC Vol. 8	N/A		
3	NO. AMRICN CRDT & CLRNG-CONTRACT	SF	FERC Vol. 8	N/A		
4	OCCIDENTAL ENERGY MARKETING, INC	SF	FERC Vol. 8	N/A		
5	SOUTHERN CALIFORNIA GAS COMPANY	SF	FERC Vol. 8	N/A		
6						
7	Municipalities:					
8	CITY OF BURBANK WATER AND POWER	SF	WSPP-2	N/A		
9						
10	Other Public Authorities:					
11	BONNEVILLE POWER AUTHORITIES	SF	WSPP-2	N/A		
12	L.A.D.W.P.	SF	WSPP-2	N/A		
13	POWEREX CORP.	SF	FERC Vol. 8	N/A		
14	SALT RIVER PROJ. AGRIC. IIMPROV	SF	WSPP-2	N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	SEATTLE CITY LIGHT MARKET	SF	WSPP-2	N/A		
2	SNOHOMISH CITY Public Utility	SF	WSPP-2	N/A		
3						
4	Tolling Units:					
5	AES HUNTINGTON BEACH LLC	LU	FERC Vol. 8	N/A		
6	BE CA LLC	LU	FERC Vol. 8	N/A		
7	BLYTHE ENERGY LLC	LU	FERC Vol. 8	N/A		
8	NRG LONG BEACH GENERATION LLC	LU	FERC Vol. 8	N/A		
9	NRG POWER MARKETING	LU	FERC No. 8	N/A		
10	RRI ENERGY - ELLWOOD INC	LU	FERC Vol. 8	N/A		
11	RRI ENERGY - ETIWANDA INC	LU	FERC Vol. 8	N/A		
12	RRI ENERGY - MANDALAY INC	LU	FERC Vol. 8	N/A		
13	SAN JOAQUIN COGEN LLC	LU	FERC Vol. 8	N/A		
14	VARIOUS SUPPLIERS	SF	FERC Vol. 8	N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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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						
2	Brokers / Other:					
3	AMEREX BROKERS LLC	OS		N/A		
4	ICAP ENERGY LLC	OS		N/A		
5	INTERCONTINENTAL EXCHANGE	OS		N/A		
6	IVG ENERGY, LTD	OS		N/A		
7	JP MORGAN	OS		N/A		
8	LANDMARK POWER EXCHANGE	OS		N/A		
9	TULLETT PREBON AMERICAS CORP					
10						
11	POWER MARKETERS DETAIL:					
12	BARCLAYS BANK PLC	SF	FERC Vol. 8	N/A		
13	BP ENERGY COMPANY	SF	FERC Vol. 8	N/A		
14	CABRILLO POWER II LLC	SF	FERC Vol. 8	N/A		
	Total					

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.

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CALPINE ENERGY SERVICES LP	SF	FERC Vol. 8	N/A		
2	CARGILL POWER MARKETS, LLC	SF	WSPP-2	N/A		
3	CONCORD ENERGY	SF	FERC Vol. 8	N/A		
4	CONOCO PHILLIPS COMPANY	SF	FERC Vol. 8	N/A		
5	CONSTELLATION ENERGY COMMODITIES	SF	FERC Vol. 8	N/A		
6	DYNEGY MORRO BAY LLC	SF	FERC Vol. 8	N/A		
7	DYNEGY MOSS LANDING LLC	SF	FERC Vol. 8	N/A		
8	DYNEGY POWER MARKETING INC.	LU	FERC Vol. 8	N/A		
9	EDF TRADING NORTH AMERICA LLC	SF	FERC Vol. 8	N/A		
10	EL PASO ELECTRIC COMPANY	SF	WSPP	N/A		
11	ELK HILLS POWER LLC	SF	FERC Vol. 8	N/A		
12	GILA RIVER POWER LLC	SF	FERC Vol. 8	N/A		
13	GLACIAL ENERGY					
14	IBERDROLA RENEWABLES, INC	SF	FERC Vol. 8	N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	IDAHO POWER	SF	WSPP	N/A		
2	J. ARON & COMPANY	SF	FERC Vol. 8	N/A		
3	J.P. MORGAN VENTURES ENERGY CORP	SF	FERC Vol. 8	N/A		
4	MACQUARIE COOK POWER INC	SF	FERC Vol. 8	N/A		
5	MIRANT ENERGY TRADING INC	SF	FERC Vol. 8	N/A		
6	MORGAN STANLEY CAPITAL GR	SF	FERC Vol. 8	N/A		
7	NEVADA POWER COMPANY	SF	FERC Vol. 8	N/A		
8	PACIFIC SUMMIT ENERGY	SF	FERC Vol. 8	N/A		
9	RRI ENERGY SERVICES INC	SF	FERC Vol. 8	N/A		
10	SEMPRA ENERGY SOLUTIONS	SF	FERC Vol. 8	N/A		
11	SEMPRA ENERGY TRADING LLC	SF	FERC Vol. 8	N/A		
12	SHELL ENERGY NO AMERICA US, L.P.	SF	FERC Vol. 8	N/A		
13	TRANSALTA ENERGY MARKETING (US)	SF	WSPP-2	N/A		
14						
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NON UTILITIES: QUALIFYING FACILITY					
2	ACE COGENERATION COMPANY	OS		N/A		
3	AES TEHACHAPI NORTHWIND	OS		N/A		
4	AES TEHACHAPI WIND (85-A)	OS		N/A		
5	AES TEHACHAPI WIND (85-B)	OS		N/A		
6	AES TEHACHAPI WIND (VG 2)	OS		N/A		
7	AES TEHACHAPI WIND (VG 3)	OS		N/A		
8	AES TEHACHAPI WIND (VG 4)	OS		N/A		
9	AES TEHACHAPI WIND (VG 1)	OS		N/A		
10	ALTA MESA PWR PUR CONTRCT	OS		N/A		
11	ALTA WIND I	OS		N/A		
12	ALTA WIND II	OS		N/A		
13	AMERICAN ENERGY INC.	OS		N/A		
14	BATES, DANIEL M, ET AL	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BERRY PETRO CO (NEWHALL I)	OS		N/A		
2	BERRY PETROLEUM (NEWHALL II)	OS		N/A		
3	BNY WESTERN TRUST CO	OS		N/A		
4	BOX CAR I PPCT	OS		N/A		
5	BOX CAR II PPCT	OS		N/A		
6	CALICO SOLAR, LLC PART I			N/A		
7	CALICO SOLAR, LLC PART II			N/A		
8	CALLEGUAS MUN WTR DIST	OS		N/A		
9	CALLEGUAS MWD 1-CONEJO	OS		N/A		
10	CALLEGUAS MWD 2-CHATSWRTH	OS		N/A		
11	CALLEGUAS MWD 3-SNTA ROSA	OS		N/A		
12	CALWIND RESOURCES INC	OS		N/A		
13	CALWIND RESOURCES INC	OS		N/A		
14	CAMBRIAN ENERGY WOODVILLE	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CAMERON RIDGE LLC III	OS		N/A		
2	CAMERON RIDGE LLC IV	OS		N/A		
3	CARSON COGENERATION	OS		N/A		
4	CENTRAL HYDRO/ISABELLA	OS		N/A		
5	CHEVRON USA #2	OS		N/A		
6	CITY OF OXNARD	OS		N/A		
7	CITY OF SANTA ANA	OS		N/A		
8	CLAREMONT TENNIS CLUB	OS		N/A		
9	COLMAC ENERGY	OS		N/A		
10	COMMERCE REFUSE	OS		N/A		
11	CORAM ENERGY GROUP LTD	OS		N/A		
12	CORMAN ENERGY LLC	OS		N/A		
13	CORMAN ENERGY LLC	OS		N/A		
14	CORONA ENERGY PARTNRS LTD	OS		N/A		
	Total					

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.
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1	COSO CLEAN POWER, LLC	OS		N/A		
2	COSO ENERGY DEVELOPERS	OS		N/A		
3	COSO FINANCE PARTNERS	OS		N/A		
4	COSO POWER DEVELOPERS	OS		N/A		
5	COUNTY SAN DIS OF OC	OS		N/A		
6	CRIMSON RESOURCE DIS OF O.C.	OS		N/A		
7	CTV PPCT	OS		N/A		
8	DEEP SPRINGS COLLEGE	OS		N/A		
9	DEL RANCH, LTD/NILAND 2	OS		N/A		
10	DESERT POWER CO	OS		N/A		
11	DESERT WATER AGCY/WHTEWTR	OS		N/A		
12	DESERT WIND I PPCT	OS		N/A		
13	DESERT WIND II PPCT	OS		N/A		
14	DESERT WIND III PPCT	OS		N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	DESERT WTR AGCY/SNOWCREEK	OS		N/A		
2	DIFWIND FARMS LTD V	OS		N/A		
3	DIFWIND PARTNERS LTD	OS		N/A		
4	DILLON ENERGY, INC	OS		N/A		
5	DUTCH ENERGY	OS		N/A		
6	EDOM HILLS PROJECT 1	OS		N/A		
7	ELMORE, LTD/NILAND 3	OS		N/A		
8	ENERGY DEV & CONSTR CORP	OS		N/A		
9	EUI MANAGEMENT PH, INC.	OS		N/A		
10	EXXON COMPANY, USA	OS		N/A		
11	FPL ENERGY CABAZON WIND	OS		N/A		
12	FSE BLYTHE I, LLC	OS		N/A		
13	GENERATING RES REC PTNRS	OS		N/A		
14	GEYSERS POWER CO LLC QFID	OS		N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	GOLETA WATER DISTRICT	OS		N/A		
2	GOSHEN PHASE II LLC	OS		N/A		
3	GREENHUNTER ENERGY	OS		N/A		
4	HANSON AGGREGATES WRP	OS		N/A		
5	HEBER GEOTHERMAL CO	OS		N/A		
6	HI HEAD HYDRO, INC	OS		N/A		
7	IMPERIAL VALLEY RES RECOVERY	OS		N/A		
8	INLAND EMPIRE UTIL AGENCY	OS		N/A		
9	KAWEAH RIVER POWER AUTH	OS		N/A		
10	KERN RIVER COGENERATION	OS		N/A		
11	L A CO SAN #2 (P HILLS A)	OS		N/A		
12	L A CO SAN #2 (P HILLS B)	OS		N/A		
13	L A CO SAN #2 (SPADRA)	OS		N/A		
14	L A, COUNTY OF - PITCHESS RANCH	OS		N/A		
Total						

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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	L A CO FLOOD CONTOL DIST	OS		N/A		
2	LEATERS, L P (NILAND 4)	OS		N/A		
3	LOMA LINDA UNIV #1	OS		N/A		
4	LONG BEACH, CITY OF/SERRF	OS		N/A		
5	LOWER TULE RIVER IRRIG	OS		N/A		
6	LUZ SOLAR PARTNERS III	OS		N/A		
7	LUZ SOLAR PARTNERS IV	OS		N/A		
8	LUZ SOLAR PARTNERS IX	OS		N/A		
9	LUZ SOLAR PARTNERS V	OS		N/A		
10	LUZ SOLAR PARTNERS VI	OS		N/A		
11	LUZ SOLAR PARTNERS VII	OS		N/A		
12	LUZ SOLAR PARTNERS VIII	OS		N/A		
13	MAMMOTH PACIFIC #1	OS		N/A		
14	MAMMOTH PACIFIC #2	OS		N/A		
	Total					

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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	MAMMOTH PACIFIC L.P. I	OS		N/A		
2	MESA WIND POWER CORP	OS		N/A		
3	MIDWAY SUNSET COGEN	OS		N/A		
4	MM TAJIGUAS ENERGY LLC 1	OS		N/A		
5	MOGUL WIND PARTNERSHIP I	OS		N/A		
6	MOJAVE COGENERATION CO	OS		N/A		
7	MONTE VISTA WATER DIST	OS		N/A		
8	MONTECITO WATER DIST	OS				
9	MOSS, RICHARD	OS		N/A		
10	MWD CORONA	OS		N/A		
11	MWD RED MOUNTAIN	OS		N/A		
12	MWD TEMESCAL	OS		N/A		
13	MWD VENICE	OS		N/A		
14	NAWD INC (EAST WINDS PRO)	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	OAK CREEK ENGY SYS INC II	OS		N/A		
2	OLS ENERGY - CAMARILLO	OS		N/A		
3	OLS ENERGY - CHINO	OS		N/A		
4	ORMESA GEOTHERMAL 1 #310	OS		N/A		
5	ORNI 18, LLC	OS		N/A		
6	OXNARD, E F, INC	OS		N/A		
7	PACIFICORP	OS		N/A		
8	PAINTED HILLS WIND DEV	OS		N/A		
9	PALM SPRINGS MUNICIPAL CO	OS		N/A		
10	PALM SPRINGS SUNRISE PLZ	OS		N/A		
11	PROCTER & GAMBLE/OXNARD 2	OS		N/A		
12	PUGET SOUND ENERGY	OS		N/A		
13	PUGET SOUND ENERGY II	OS		N/A		
14	RANCHO SIMI PROJ #1	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	RANCHO SIMI PROJ #2	OS		N/A		
2	RHODIA, INC	OS		N/A		
3	RIDGETOP ENERGY, LLC I	OS		N/A		
4	RIDGETOP ENERGY, LLC II	OS		N/A		
5	RIO BRAVO JASMIN	OS		N/A		
6	RIPON COGENERATION, INC.	OS		N/A		
7	RIVERSIDE CTY WASTE MGMT	OS		N/A		
8	ROYAL FARMS	OS		N/A		
9	ROYAL FARMS #2	OS		N/A		
10	SALTON SEA IV	OS		N/A		
11	SALTON SEA POWER GEN #1	OS		N/A		
12	SALTON SEA POWER GEN #2	OS		N/A		
13	SALTON SEA POWER GEN #3	OS		N/A		
14	SAN BERNARDINO MWD 1	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SAN BERNARDINO MWD 3	OS		N/A		
2	SAN GORGONIO FARMS, INC	OS		N/A		
3	SAN GORGONIO WESTWINDS II	OS		N/A		
4	SAN GORGONIO WIND FARMS	OS		N/A		
5	SEARLESS VALLEY MINERALS	OS		N/A		
6	SEARLESS VALLEY MINERALS	OS		N/A		
7	SEC 16-29 TRUST -ALT III	OS		N/A		
8	SECOND IMPERIAL GEO CO	OS		N/A		
9	SECTION 20 TRUST	OS		N/A		
10	SECTION 22 TRUST (SN JAC)	OS		N/A		
11	SIERRA SUNTOWER, LLC	OS		N/A		
12	SKY RVR PTNRSHWP-WILD I	OS		N/A		
13	SKY RVR PTNRSHWP-WILD II	OS		N/A		
14	SKY RVR PTNRSHWP-WILD III	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	SUNRAY ENERGY, INC.	OS		N/A		
2	SYCAMORE COGENERATION	OS		N/A		
3	TEHACHAPI PWR PUR TRUST	OS		N/A		
4	TERRA-GEN 251 WIND X	OS		N/A		
5	TERRA-GEN 251 WIND XI	OS		N/A		
6	TERRA-GEN 251 WIND XII	OS		N/A		
7	TERRA-GEN 251 WIND XIII	OS		N/A		
8	TERRA-GEN DIXIE VALLEY	OS		N/A		
9	THE BANK OF NY TRUST CO	OS		N/A		
10	THE TERMO COMPANY	OS		N/A		
11	THREE VALLEYS MWD FULRTN	OS		N/A		
12	THREE VALLEYS MWD MIRAMAR	OS		N/A		
13	THREE VALLEYS MWD WILLMS	OS		N/A		
14	TIN INC DBA TEMPLE-INLD	OS		N/A		
	Total					

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.
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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	TOYON LANDFILL GAS CONV	OS		N/A		
2	U S BORAX & CHEMICAL	OS		N/A		
3	VENTURA REGIONAL SANITATION DIST	OS		N/A		
4	VICTORY GARDEN/PHASE IV	OS		N/A		
5	VICTORY GARDEN/PHASE IV	OS		N/A		
6	VICTORY GARDEN/PHASE IV	OS		N/A		
7	VULCAN/BN GEOTHERMAL	OS		N/A		
8	W.M. ENERGY SOLUTIONS,INC	OS		N/A		
9	W.M.ENERGY SOLUTIONS,INC.	OS		N/A		
10	WALNUT VALLEY WATER DIST	OS		N/A		
11	WATSON COGENERATION CO	OS		N/A		
12	WESTWIND TRUST	OS		N/A		
13	WEYERHAEUSER COMPANY	OS		N/A		
14	WFA STATION 1 UPLAND	OS		N/A		
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	WHEELABRATOR NORWALK	OS		N/A		
2	WINDPOWER PTNRS 1993	OS		N/A		
3	WINDPOWER PTNRS 1993 L.P.	OS		N/A		
4	WINDPOWER PTNRS 1993 L.P.	OS		N/A		
5	WINDRIDGE INC	OS		N/A		
6	WINDSONG WIND PARK	OS		N/A		
7	WM ENERGY (EL SOBRANTE)	OS		N/A		
8	WM ENERGY (SIMI VALLEY)	OS		N/A		
9	ZEPHYR PARK, LTD	OS		N/A		
10						
11	SUB-TOTAL PURCHASED POWER					
12						
13	CALIFORNIA ISO - NET					
14	INDEPENDENT EVALUATOR COSTS					
	Total					

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	VARIOUS ENERGY SETTLEMENT					
2	LEASE CONVERSION					
3	WECC STATUTORY COSTS					
4	HEDGING INSTRUMENTS					
5	ACCRUAL FOR ENERGY EXCHANGE					
6	RENEWABLE ENERGY CREDITS					
7	GREEN ATTRIBUTES					
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.

5. For requirements RQ purchases and any type of service involving demand charges imposed on a monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
169				10,126		10,126	2
893				86,002		86,002	3
							4
							5
							6
					10,800	10,800	7
							8
							9
65				17,655	-151,884	-134,229	10
59				12,209		12,209	11
1,786				178,586		178,586	12
107				8,001		8,001	13
							14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
108,999			5,106,708	2,574,112		7,680,820	2
					105,362	105,362	3
127,352					354,192	354,192	4
							5
	176,328	110,066					6
		245,958					7
		727					8
104,685				3,364,699		3,364,699	9
							10
							11
534,886				25,198,916		25,198,916	12
285,921				20,993,335		20,993,335	13
2				81		81	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
							2
13,192				137,500	51,058	188,558	3
			654,000			654,000	4
					6,000	6,000	5
50,583				447,905	1,055,621	1,503,526	6
9,931				373,594		373,594	7
400				13,300		13,300	8
3,886				153,123		153,123	9
10,000				449,960		449,960	10
137					907	907	11
							12
							13
					-1,802,653	-1,802,653	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
					-5,574,687	-5,574,687	1
				801,036		801,036	2
-33,000				-1,280,000		-1,280,000	3
3,732				139,575	354,700	494,275	4
					7,331,459	7,331,459	5
							6
							7
20,794				1,240,172		1,240,172	8
							9
							10
55,460				2,402,221	94	2,402,315	11
-400				-63,800		-63,800	12
316,858			375,000	11,667,871		12,042,871	13
11,050				405,460		405,460	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
4,392				183,845	-1,000	182,845	1
1,000				44,000		44,000	2
							3
							4
			-3,736	-21,731	-24,465	-49,932	5
964,907			244,549,641	43,757,837	-55,929,272	232,378,206	6
1,044,385			18,325,272	32,614,040	2,013,137	52,952,449	7
12,369			27,068,516	630,400		27,698,916	8
-60					-1,450	-1,450	9
5,694			3,531,960	106,081	-17,633	3,620,408	10
213,805			53,286,106	11,539,750	733,561	65,559,417	11
981			6,626,980	116,554	-17,244	6,726,290	12
2,599			4,039,569	132,805	-8,943	4,163,431	13
					63,383,777	63,383,777	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
							2
					16,613	16,613	3
					10,343	10,343	4
550				27,500	80,901	108,401	5
					5,954	5,954	6
					2,620,216	2,620,216	7
					24,109	24,109	8
					2,101	2,101	9
							10
							11
247,512			216,000	17,909,336		18,125,336	12
400				12,000		12,000	13
1,056					3,400,320	3,400,320	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
8,568					25,275,600	25,275,600	1
1,015				33,290		33,290	2
					-81,616	-81,616	3
			172,500		-41,950	130,550	4
800				28,000		28,000	5
92,297			35,383,592	3,989,799	287,854	39,661,245	6
3,000					6,300,000	6,300,000	7
1,800					1,887,000	1,887,000	8
				1,645	-22,120,914	-22,119,269	9
200				4,350		4,350	10
3,960					5,940,000	5,940,000	11
5,992				248,899		248,899	12
					-39,158	-39,158	13
5,400				206,390	-8,476,615	-8,270,225	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
20					73	73	1
123,629				10,559,022		10,559,022	2
3,295				70,472		70,472	3
33,400			614,250	1,295,000		1,909,250	4
200				7,000		7,000	5
24,274				825,296	5,475,000	6,300,296	6
1,200				44,300		44,300	7
16,000				722,740	-22,674,020	-21,951,280	8
7,957					26,347,525	26,347,525	9
-436				12,300	-3,724,000	-3,711,700	10
27,200				1,145,376		1,145,376	11
48,044			243,750	1,938,782	5,773,425	7,955,957	12
2,200				92,100		92,100	13
							14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
							1
789,927			20,315,178	49,899,694		70,214,872	2
8,584			121,654	374,789		496,443	3
20,488			296,419	853,218		1,149,637	4
28,164			508,724	1,186,647		1,695,371	5
10,847			125,427	459,690		585,117	6
9,565			133,065	412,345		545,410	7
8,842			112,770	373,619		486,389	8
12,014			132,856	514,800		647,656	9
60,191			1,755,962	2,514,498		4,270,460	10
2,761				162,672		162,672	11
2,390				147,604		147,604	12
691			5,615	28,240		33,855	13
1,142			35,920	53,259		89,179	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

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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)	
165,603			1,802,612	7,125,019		8,927,631	1
142,883			652,869	6,122,593		6,775,462	2
35,300			437,633	2,231,047		2,668,680	3
10,748			212,798	475,330		688,128	4
19,269			433,738	842,269		1,276,007	5
					-4,125,000	-4,125,000	6
					-8,625,000	-8,625,000	7
1,535			10,900	63,181		74,081	8
4			192	-16		176	9
4,033			137,007	166,746		303,753	10
441			16,598	17,853		34,451	11
15,446			82,010	675,807		757,817	12
50,478			240,676	2,112,464		2,353,140	13
-264			-267	-12,423		-12,690	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
132,515			2,510,109	8,306,874		10,816,983	1
35,309			724,503	2,215,234		2,939,737	2
340,472			9,053,404	15,458,567		24,511,971	3
38,056			1,899,987	1,585,587		3,485,574	4
219			249	7,038		7,287	5
				3		3	6
22			57	919		976	7
			1	-47		-46	8
363,038			10,339,387	22,983,249		33,322,636	9
73,719			1,839,948	6,627,939		8,467,887	10
10,838			125,101	466,354		591,455	11
28,960			128,918	1,243,115		1,372,033	12
					-90,000	-90,000	13
134,015			6,541,040	6,835,591		13,376,631	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
565,853				46,328,850		46,328,850	1
471,927			11,820,293	29,854,577		41,674,870	2
543,575			12,095,176	34,268,776		46,363,952	3
23,790			182,314	1,464,521		1,646,835	4
17			82	864		946	5
17			17	160		177	6
32,339			671,388	1,331,521		2,002,909	7
				3		3	8
340,004			8,236,896	21,472,339		29,709,235	9
1,590			6,928	63,480	54,824	125,232	10
4,081			80,924	176,458		257,382	11
77,285			1,791,800	4,793,004		6,584,804	12
196,771			4,375,649	11,901,147		16,276,796	13
76,946			1,991,389	4,794,985		6,786,374	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
294			8,744	12,585		21,329	1
14,237			352,490	601,895		954,385	2
25,179			638,410	1,006,649		1,645,059	3
150,410				9,170,761		9,170,761	4
21,216			618,553	896,888		1,515,441	5
48,310			907,160	3,028,091		3,935,251	6
326,550			8,238,303	20,635,129		28,873,432	7
33,661			609,510	1,452,991		2,062,501	8
46,291			1,089,573	2,909,250		3,998,823	9
7,649			52,164	344,598		396,762	10
88,118			1,268,023	5,555,325		6,823,348	11
53,051				6,103,088		6,103,088	12
-569			-535	-27,720		-28,255	13
1,969,315				107,448,411		107,448,411	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
			1	-99		-98	1
88,251				7,370,575		7,370,575	2
					-300,000	-300,000	3
1			2	33		35	4
334,957			6,724,585	21,158,596		27,883,181	5
1,789			25,791	107,320		133,111	6
79,600				7,574,095		7,574,095	7
1,269			5,344	55,047		60,391	8
53,427			2,491,380	2,314,392		4,805,772	9
1,319,478			24,626,027	51,167,721		75,793,748	10
6,254			31,377	402,377		433,754	11
387,925			9,593,353	24,613,739		34,207,092	12
41,659			1,306,701	2,677,137		3,983,838	13
172,199			3,802,194	7,483,226		11,285,420	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
21,832			569,161	971,376		1,540,537	1
344,330			7,801,293	21,766,378		29,567,671	2
1,756			9,514	64,435		73,949	3
228,244			4,560,304	20,497,924		25,058,228	4
2,512			15,074	112,947		128,021	5
72,823			4,950,606	4,776,166		9,726,772	6
75,654			4,998,901	4,950,738		9,949,639	7
227,798			18,039,046	14,998,606		33,037,652	8
66,679			5,210,761	4,359,219		9,569,980	9
81,306			5,711,487	5,337,266		11,048,753	10
76,330			5,655,282	5,019,146		10,674,428	11
215,774			15,600,386	14,255,580		29,855,966	12
50,416			977,569	3,181,097		4,158,666	13
83,747			1,456,168	5,230,193		6,686,361	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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 monthly (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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
103,130			2,150,803	6,465,069		8,615,872	1
52,598			301,118	2,219,559		2,520,677	2
1,420,418			17,672,955	60,666,045		78,339,000	3
22,837				1,706,568		1,706,568	4
8,820				667,370		667,370	5
351,971			8,015,082	15,246,510		23,261,592	6
487			5,483	20,660		26,143	7
629			17,763	26,936		44,699	8
467			10,454	19,240		29,694	9
19,084				1,809,128		1,809,128	10
32,336				2,956,141		2,956,141	11
19,775				1,876,057		1,876,057	12
8,663				995,709		995,709	13
8,526			193,702	359,731		553,433	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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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)	
77,051			1,948,390	4,854,565		6,802,955	1
216,233			4,821,149	11,005,334		15,826,483	2
216,899			4,838,317	11,028,229		15,866,546	3
422,903			8,844,719	26,673,539		35,518,258	4
182,262				15,375,559		15,375,559	5
136,247			9,860,769	6,991,020		16,851,789	6
327,600				24,189,979		24,189,979	7
34,891			493,111	2,195,101		2,688,212	8
113			73	4,792		4,865	9
1,066			6,184	39,295		45,479	10
397,185			11,467,102	17,366,255		28,833,357	11
1,119,960				80,989,190		80,989,190	12
113,200				7,253,332		7,253,332	13
67			24	3,718		3,742	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
-3			-4	-151		-155	1
5,521			24,691	246,101		270,792	2
142,418			2,773,705	5,907,089		8,680,794	3
78,677			2,062,171	5,133,797		7,195,968	4
266,594			7,200,342	16,895,069		24,095,411	5
135,657			6,755,025	6,978,377		13,733,402	6
6,612				671,321		671,321	7
86			108	3,667		3,775	8
275			411	12,107		12,518	9
340,919			7,575,420	27,760,706		35,336,126	10
78,651			2,290,259	7,044,727		9,334,986	11
123,239			3,252,309	7,801,050		11,053,359	12
376,500			9,532,915	23,823,633		33,356,548	13
357			3,583	15,175		18,758	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
245			129	10,469		10,598	1
62,164			329,590	2,603,926		2,933,516	2
28,754			644,487	1,803,850		2,448,337	3
7,244			35,173	300,596		335,769	4
			124	-10,598		-10,474	5
98,065			1,648,726	5,579,176		7,227,902	6
75,461			1,704,605	3,039,132		4,743,737	7
244,813			6,851,132	15,512,767		22,363,899	8
38,171			896,490	1,581,064		2,477,554	9
41,986			902,869	1,781,119		2,683,988	10
610			9,132	27,378	-16,450	20,060	11
81,224			1,560,128	5,062,274		6,622,402	12
43,231			715,470	2,680,225		3,395,695	13
43,869			589,690	2,717,950		3,307,640	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
48,168			5,755,280	1,878,112		7,633,392	1
1,529,747			25,221,858	66,540,101		91,761,959	2
107,553			2,275,060	6,671,549		8,946,609	3
10,073			156,714	416,710		573,424	4
7,528			119,446	306,720		426,166	5
9,387			151,213	592,076		743,289	6
7,189			105,536	451,755		557,291	7
437,899			10,780,911	27,608,391		38,389,302	8
3,825			99,808	240,465		340,273	9
33			143	1,372		1,515	10
1,248			31,141	53,923		85,064	11
826			24,906	35,496		60,402	12
1,834			44,817	78,948		123,765	13
91,658			2,675,781	4,078,982		6,754,763	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
5,413			7,837	256,641		264,478	1
192,029			773,941	8,206,062		8,980,003	2
6,912				697,139		697,139	3
15,316			250,467	972,186		1,222,653	4
12,459			219,304	799,637		1,018,941	5
15,242			204,947	956,762		1,161,709	6
300,223			5,784,401	18,959,605	-600,000	24,144,006	7
17,827			102,729	1,696,439	14,307	1,813,475	8
11,108			11,992	1,115,988		1,127,980	9
752			16,629	32,679		49,308	10
2,196,574			31,255,944	95,802,453		127,058,397	11
25,538			673,562	1,082,045		1,755,607	12
109,588			2,602,463	4,828,411		7,430,874	13
141			767	5,608		6,375	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
87,606			5,003,952	5,138,619		10,142,571	1
11,641			116,595	728,410		845,005	2
12,787			123,181	798,858		922,039	3
25,090			242,721	1,578,003		1,820,724	4
1,528			9,928	68,042		77,970	5
292			907	16,891	60	17,858	6
3,565				296,218		296,218	7
2,777				232,610		232,610	8
8,996			192,617	563,341		755,958	9
							10
							11
							12
6,121,400			3,055,134	402,303,050	-54,648,949	350,709,235	13
					720,919	720,919	14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

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 monthly (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)	
					-41,438,286	-41,438,286	1
					-7,759,118	-7,759,118	2
					4,774,160	4,774,160	3
					120,057,118	120,057,118	4
				1,814,620		1,814,620	5
							6
					6,298,421	6,298,421	7
							8
							9
							10
							11
							12
							13
							14
35,307,844	176,328	356,751	866,219,236	1,992,065,585	52,477,204	2,910,762,025	

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

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

The following reference table applies to transactions with a statistical class code of "OS" which require footnote disclosure as to the nature of the service. To facilitate completion and reduce unnecessary repetition, please refer to this table for all "OS" classifications.

- OS1 "Evergreen" Means Minimum of one year, with automatic annual renewal thereafter. The availability and reliability of energy delivered is on an as-available basis.
- OS2 Long-Term Power Purchase Agreements with Renewable / Alternative Resources. "Long-Term" means five years or greater. The availability and reliability of energy delivery must match the dedicated firm MW as specified in the Contract.
- OS3 Evergreen Power Purchase Agreement with Renewable / Alternative Resources less than 100 KW. "Evergreen" means minimum of one year, with automatic annual renewal thereafter. The availability and reliability or energy delivered is on an as-available basis.
- OS4 Long-Term Power Purchase Agreements with Renewable / Alternative Resources. "Long-Term" means five years or greater. The availability and reliability of energy delivered is on an as available basis.
- OS7 Long-Term Power Purchase Agreements with Renewable / Alternative Resources. "Long-Term" means five years or greater. The availability and reliability of energy delivery must match the dedicated firm MW as specified in the Contract.
- OS8 SCE customers on the fringe of SCE's service area.
- OS9 Termination Agreement.
- OS10 Replacement for lost energy due to diversion from Mill Creek.
- OS11 Settlement for generation deviation from transmission service schedule.
- OS12 Quarterly Payments - U.S. Department of Interior, Bureau of Reclamation, Lower Colorado River Multi-Species Conservation Program.
- OS13 Brokers.

Schedule Page: 326 Line No.: 2 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

Facility Charges

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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OS 8 - Please reference page 326 Line 1 Column (b).

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

LF - TERMINATION DATE: 09/30/2017.

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

OS 12 - Please reference page 326 Line 1 Column (b).

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

Conservation Program.

Schedule Page: 326.1 Line No.: 4 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

OS 11 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

Sale of Gas.

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.2 Line No.: 14 Column: I

Sale of Gas.

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

Sale of Gas.

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Sale of gas.

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

Transportation.

Schedule Page: 326.3 Line No.: 11 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.4 Line No.: 1 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.4 Line No.: 5 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Transportation.

Sale of Gas.

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Transportation.

Sale of Gas.

Schedule Page: 326.4 Line No.: 7 Column: I

Transportation.

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

RA Capacity.

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

Transportation.

Sale of Gas.

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

Transportation.

Sale of Gas.

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

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Transportation.
Sale of Gas.

Schedule Page: 326.4 Line No.: 13 Column: I

Transportation.

Capital Lease under GAAP.

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Net Gas Purchase Plus Imbalances.

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

OS 13 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

OS 13 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

OS 13 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

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

OS 13 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.5 Line No.: 7 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 7 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.5 Line No.: 8 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 8 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.5 Line No.: 9 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.5 Line No.: 14 Column: I

RA Capacity.

Schedule Page: 326.6 Line No.: 1 Column: I

RA Capacity.

Schedule Page: 326.6 Line No.: 3 Column: I

Transportation.

Sale of Gas.

Schedule Page: 326.6 Line No.: 4 Column: I

Sale of Gas.

Schedule Page: 326.6 Line No.: 6 Column: I

Transportation.

Sale of Gas.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Schedule Page: 326.6 Line No.: 7 Column: I

RA Capacity.

Schedule Page: 326.6 Line No.: 8 Column: I

RA Capacity.

Schedule Page: 326.6 Line No.: 9 Column: I

Sale of Gas.

Schedule Page: 326.6 Line No.: 11 Column: I

RA Capacity.

Schedule Page: 326.6 Line No.: 13 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.6 Line No.: 14 Column: I

Sale of Gas.

Schedule Page: 326.7 Line No.: 1 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.7 Line No.: 6 Column: I

RA Capacity.

Sale of Gas.

Schedule Page: 326.7 Line No.: 8 Column: I

Sale of Gas.

Schedule Page: 326.7 Line No.: 9 Column: I

RA Capacity.

Schedule Page: 326.7 Line No.: 10 Column: I

RA Capacity.

Schedule Page: 326.7 Line No.: 12 Column: I

RA Capacity.

Sale of Gas.

Schedule Page: 326.8 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 13 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Schedule Page: 326.8 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 2 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 6 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.9 Line No.: 7 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.9 Line No.: 8 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 13 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 5 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 6 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 7 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 8 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Schedule Page: 326.10 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.10 Line No.: 13 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.10 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 6 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 8 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 10 Column: I

Termination Date: 01/19/2036.

Schedule Page: 326.11 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.11 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

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OS 4 - Please reference page 326 Line 1 Column (b).

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OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 10 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.12 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 1 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 3 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.13 Line No.: 4 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 7 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 8 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 11 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.13 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 3 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Schedule Page: 326.14 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 7 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 8 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 11 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.14 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 2 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 5 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 7 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 11 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.15 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 1 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 2 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 11 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.16 Line No.: 14 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 1 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 2 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 5 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 8 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 10 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 11 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 12 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.17 Line No.: 13 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA

Schedule Page: 326.17 Line No.: 14 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 1 Column: b

OS 3 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 5 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 8 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 11 Column: l

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.18 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.18 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 8 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 10 Column: b

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.19 Line No.: 14 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 2 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 7 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 7 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.20 Line No.: 8 Column: b

OS 7 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 8 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.20 Line No.: 9 Column: b

OS 7 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 11 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.20 Line No.: 14 Column: b

OS 1 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 3 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 4 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 5 Column: b

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 6 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 6 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.21 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 9 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.21 Line No.: 13 Column: I

California ISO Costs.

Schedule Page: 326.21 Line No.: 14 Column: I

Independent Evaluator Costs.

Schedule Page: 326.22 Line No.: 1 Column: I

Various Energy Settlement Refunds.

Schedule Page: 326.22 Line No.: 2 Column: I

Capital Lease under GAAP.

Schedule Page: 326.22 Line No.: 3 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Schedule Page: 326.22 Line No.: 4 Column: I

Expenses related to collateral requirements, trust fund management, and miscellaneous other expense.

Realized Gain / Loss on Financial Futures or Options.

Unrealized Gain / Loss on Financial Futures or Options.

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	Southern California Water Company	Various	Southern California Water Company	OLF
2	Southern California Water Company	Southern California Water Company	Southern California Water Company	OLF
3	Southern California Water Company	Southern California Water Company	Southern California Water Company	AD
4	City of Azusa	Various	City of Azusa	OLF
5	City of Azusa	Various	City of Azusa	AD
6	City of Azusa	Various	City of Azusa	OLF
7	City of Azusa	Various	City of Azusa	OLF
8	City of Azusa	Various	City of Azusa	OLF
9	City of Azusa	City of Pasadena	City of Azusa	OLF
10	City of Azusa	Various	City of Azusa	OLF
11	City of Azusa	Various	City of Azusa	OLF
12	City of Banning	Various	City of Banning	OLF
13	City of Banning	Various	City of Banning	AD
14	City of Banning	Various	City of Banning	OLF
15	City of Banning	Various	City of Banning	OLF
16	City of Banning	Various	City of Banning	OLF
17	City of Banning	Various	City of Banning	OLF
18	City of Victorville	Various	City of Victorville	OLF
19	City of Victorville	Various	City of Victorville	AD
20	City of Victorville	Various	City of Victorville	OLF
21	City of Victorville	Various	City of Victorville	AD
22	City of Victorville	Various	City of Victorville	OLF
23	City of Victorville	Various	City of Victorville	AD
24	City of Colton	Various	City of Colton	OLF
25	City of Colton	Various	City of Colton	AD
26	City of Colton	Various	City of Colton	OLF
27	City of Colton	Various	City of Colton	OLF
28	City of Colton	Various	City of Colton	OLF
29	City of Colton	Various	City of Colton	OLF
30	City of Colton	Various	City of Colton	OLF
31	City of Riverside	Various	City of Riverside	OLF
32	City of Riverside	Various	City of Riverside	OLF
33	City of Riverside	Various	City of Riverside	OLF
34	City of Riverside	Various	City of Riverside	OLF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	City of Riverside	Various	City of Riverside	OLF
2	City of Vernon	Various	City of Vernon	OLF
3	City of Corona	Various	City of Corona	OLF
4	City of Corona	Various	City of Corona	AD
5	City of Corona	Various	City of Corona	OLF
6	City of Corona	Various	City of Corona	AD
7	City of Corona	Various	City of Corona	OLF
8	City of Corona	Various	City of Corona	AD
9	City of Corona	Various	City of Corona	OLF
10	City of Corona	Various	City of Corona	AD
11	City of Corona	Various	City of Corona	OLF
12	City of Corona	Various	City of Corona	AD
13	City of Vernon	Various	City of Vernon	OLF
14	City of Vernon	Various	City of Vernon	AD
15	City of Vernon	Various	City of Vernon	OLF
16	Southwest Trans Elec Pwr Coop - AEPCO	Various	Southwest Trans Elec Pwr Coop - A	OLF
17	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
18	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
19	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
20	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
21	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
22	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
23	City of Moreno Valley	Various	City of Moreno Valley	OLF
24	City of Moreno Valley	Various	City of Moreno Valley	AD
25	City of Moreno Valley	Various	City of Moreno Valley	OLF
26	City of Moreno Valley	Various	City of Moreno Valley	AD
27	City of Moreno Valley	Various	City of Moreno Valley	OLF
28	City of Moreno Valley	Various	City of Moreno Valley	AD
29	City of Moreno Valley	Various	City of Moreno Valley	OLF
30	City of Moreno Valley	Various	City of Moreno Valley	AD
31	City of Moreno Valley	Various	City of Moreno Valley	OLF
32	City of Moreno Valley	Various	City of Moreno Valley	AD
33	City of Moreno Valley	Various	City of Moreno Valley	OLF
34	City of Moreno Valley	Various	City of Moreno Valley	AD
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.

2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).

3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)

4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
2	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
3	Industry Urban Development Agency	Various	Industry Urban Development Agenc	OLF
4	Industry Urban Development Agency	Various	Industry Urban Development Agenc	AD
5	Arizona Public Service	Various	Arizona Public Service	OLF
6	Arizona Public Service	Various	Arizona Public Service	AD
7	Department of Water Resources	Various	Department of Water Resources	OLF
8	Department of Water Resources	Various	Department of Water Resources	AD
9	Department of Water Resources	Various	Department of Water Resources	OLF
10	Department of Water Resources	Various	Department of Water Resources	AD
11	Department of Water Resources	Various	Department of Water Resources	OLF
12	City of Victorville	Various	City of Victorville	OLF
13	City of Victorville	Various	City of Victorville	AD
14	Southwest Transmission Cooperative	Various	City of Anza	OLF
15	Southwest Transmission Cooperative	Various	City of Anza	AD
16	Department of Water Resources	Various	Department of Water Resources	AD
17	City of Pasadena	Various	City of Pasadena	AD
18	City of Pasadena	Various	City of Pasadena	OLF
19	City of Los Angeles	Various	City of Los Angeles	OLF
20	Department of Water Resources	Various	Department of Water Resources	OLF
21	Department of Water Resources	Various	Department of Water Resources	OLF
22	Department of Water Resources	Various	Department of Water Resources	OLF
23	Department of Water Resources	Various	Department of Water Resources	AD
24	Department of Water Resources	Various	Department of Water Resources	OLF
25	Department of Water Resources	Various	Department of Water Resources	OLF
26	Department of Water Resources	Various	Department of Water Resources	OLF
27	Department of Water Resources	Various	Department of Water Resources	OLF
28	Department of Water Resources	Various	Department of Water Resources	OLF
29	M-S-R Public Power Authority	Various	Pacific Gas & Electric Company	OLF
30	AES Huntington Beach, LLC	AES Huntington Beach	ISO	OLF
31	Reliant Energy Mandalay, LLC	Ocean Vista Power Generation	ISO	OLF
32	Reliant Energy Coolwater, LLC	Alta Power Generation	ISO	OLF
33	Reliant Energy Ormond Bch, LLC	Ormond Beach Generation	ISO	OLF
34	Southwest Trans Elec Pwr Coop - AEPCO	Various	Southwest Trans Elec Pwr Coop - A	OLF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	High Desert Power Trust	Various	High Desert Power Trust	OLF
2	Inland Empire Energy Center	Various	Inland Empire Energy Center	OLF
3	Southern California Water Company	Various	Southern California Water Company	OLF
4	Southern California Water Company	Various	Southern California Water Company	AD
5	Department of Water Resources	Various	Department of Water Resources	OLF
6	Department of Water Resources	Various	Department of Water Resources	AD
7	Department of Water Resources	Various	Department of Water Resources	OLF
8	Department of Water Resources	Various	Department of Water Resources	AD
9	Department of Water Resources	Various	Department of Water Resources	OLF
10	Department of Water Resources	Various	Department of Water Resources	AD
11	Department of Water Resources	Vaiious	Department of Water Resources	OLF
12	Department of Water Resources	Various	Department of Water Resources	AD
13	Department of Water Resources	Various	Department of Water Resources	OLF
14	Department of Water Resources	Various	Department of Water Resources	AD
15	Department of Water Resources	Various	Department of Water Resources	OLF
16	Department of Water Resources	Various	Department of Water Resources	AD
17	City of Corona	Various	City of Corona	OLF
18	City of Corona	Various	City of Corona	AD
19	City of Moreno Valley	Various	City of Moreno Valley	OLF
20	City of Moreno Valley	Various	City of Moreno Valley	AD
21	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
22	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
23	ISO Wheeling	N/A	N/A	OS
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
349.8	Various	Various				1
Vol. 5, SA #4	Victor / Vista Sub.	Cottonwood / Zanja	39	148,877	143,612	2
Vol. 5, SA #4	Victor / Vista Sub.	Cottonwood / Zanja	39			3
Vol. 5, SA #2	Rio Hondo	Azusa		196,426	193,068	4
Vol. 5, SA #2	Rio Hondo	Azusa				5
Vol. 5, SA #2	Rio Hondo	Azusa				6
373	Victorville-Lugo	Rio Hondo	4			7
372	Mead	Rio Hondo	4			8
374	Victorville-Lugo	Rio Hondo	14			9
375	Mead / Rio Hondo	Rio Hondo / Mead	8			10
376	Sylmar	Rio Hondo	10			11
Vol. 5, SA #3	Near Devers	Banning		145,162	140,806	12
Vol. 5, SA #3	Near Devers	Banning				13
379	Victorville-Lugo	Devers	3			14
381	Devers	Devers	15			15
378	Mead	Devers	2			16
380	Victorvle-Lugo-Ban	Banning/VctrvllLugo	5			17
Vol. No. 6	Victor Sub	Vctrvle 12kV Intcnt		9,539	9,539	18
Vol. No. 6	Victor Sub	Vctrvle 12kV Intcnt		29,014	29,014	19
Vol. No. 6	Victor Sub	SCE Cement 33kV line		12,034	12,034	20
Vol. No. 6	Victor Sub	SCE Cement 33kV line		14,718	14,718	21
Vol.5, SA#231	Victor Sub	City of Victorville		36,927	35,967	22
Vol.5, SA#231	Victor Sub	City of Victorville				23
Vol. 5, SA #1	Vista	City of Colton		327,640	326,198	24
Vol. 5, SA #1	Vista	City of Colton				25
362	Victorville-Lugo	Vista	3			26
365	Devers	Vista				27
361	Mead	Vista	3			28
see footnote	Various	Various				29
363	Victorville-Lugo	Vista	18			30
Vol. 5, SA #5	Vista	Riverside City Limit		2,090,448	2,081,877	31
393.2	San Onofre	Vista	42			32
392.2	Victorville-Lugo	Vista	12			33
391.2	Victorville-Lugo	Vista	156			34
			5,039	10,723,992	10,686,988	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
390.2	Mead	Vista	30			1
359.1	Laguna Bell	Vernon				2
Vol. 5, SA 151	Mira Loma	Corona Sunkist	1	3,804	3,707	3
Vol. 5, SA 151	Mira Loma	Corona Sunkist	1			4
Vol. 5, SA 125	Mira Loma	Corona Dos Lagos	1	18,528	17,299	5
Vol. 5, SA 125	Mira Loma	Corona Dos Lagos	1			6
Vol. 5, SA 97	Mira Loma	Corona Pointe		21,002	20,382	7
Vol. 5, SA 97	Mira Loma	Corona Pointe				8
Vol. 5, SA 77	Mira Loma	Crossing Bus. Ctr.		22,702	21,629	9
Vol. 5, SA 77	Mira Loma	Crossing Bus. Ctr.				10
Vol. 5, SA 130	Mira Loma	Cleargen Sub		12,958	12,823	11
Vol. 5, SA 130	Mira Loma	Cleargen Sub				12
207.26	Mead	Laguna Bell	26			13
207.26	Mead	Laguna Bell	26			14
360.2	Victorville-Lugo	Laguna Bell	75			15
131	Mead	Mountain Center				16
Vol. 5, SA 165	Walnut Sub,220kV bus	Industry-Anhm-Puente	2	16,925	16,745	17
Vol. 5, SA 165	Walnut Sub,220kV bus	Industry-Anhm-Puente	2			18
Vol. 5, SA #48	Walnut Sub,230kV bus	Industry-Old Rnch Rd		21,618	20,559	19
Vol. 5, SA #48	Walnut Sub,230kV bus	Industry-Old Rnch Rd				20
Vol. 5, SA 152	Chino Sub,220kV bus	Industry-Wadghm Way	2	8,797	8,316	21
Vol. 5, SA 152	Chino Sub,220kV bus	Industry-Wadghm Way	2			22
Vol. 5, SA 103	Valley Sub	Moreno Valley		805	792	23
Vol. 5, SA 103	Valley Sub	Moreno Valley				24
Vol. 5, SA 143	Valley Sub	Moreno Valley	1	5,243	5,102	25
Vol. 5, SA 143	Valley Sub	Moreno Valley	1			26
Vol. 5, SA 128	Valley Sub	Moreno Valley		4,983	4,875	27
Vol. 5, SA 128	Valley Sub	Moreno Valley				28
Vol. 5, SA 117	Valley Sub	Moreno Valley	1	18,527	18,253	29
Vol. 5, SA 117	Valley Sub	Moreno Valley	1			30
Vol. 5, SA 115	Valley Sub	Moreno Valley		8,551	8,397	31
Vol. 5, SA 115	Valley Sub	Moreno Valley				32
Vol. 5, SA 149	Valley Sub	Moreno Valley	12	61,355	61,091	33
Vol. 5, SA 149	Valley Sub	Moreno Valley	12			34
			5,039	10,723,992	10,686,988	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Vol. 5, SA #89	Etiwanda	City/Rncho Cucamonga		66,766	66,292	1
Vol. 5, SA #89	Etiwanda	City/Rncho Cucamonga				2
Vol. No. 6	Walnut	City of Industry		12,218	12,218	3
Vol. No. 6	Walnut	City of Industry		31,739	31,739	4
Vol. 5, SA 193	Various	Various		33,883	32,284	5
Vol. 5, SA 193	Various	Various				6
Vol. 5, SA#56	Vista	Cherry Valley Statn		493	459	7
Vol. 5, SA#56	Vista	Cherry Valley Statn				8
Vol. 5, SA#57	Vista	Crafton Hills Statn		14,795	14,679	9
Vol. 5, SA#57	Vista	Crafton Hills Statn				10
Vol. 5, SA#58	San Bernardino	Greenspot Station	4	11,343	11,136	11
Vol. 5, SA#218	Victor Sub	City of Victorville		22,923	22,376	12
Vol. 5, SA#218	Victor Sub	City of Victorville				13
Vol. 5, SA#179	Mountain Center	Anza	1	54,249	50,002	14
Vol. 5, SA#179	Mountain Center	Anza	1			15
Vol. 5, SA#58	San Bernardino	Greenspot Station	4			16
317	Rio Hondo	Goodrich				17
55.7	Various	Goodrich	200			18
219	Various	Various	368	2,578,853	2,578,853	19
342	Mohave	Vincent	28			20
113	El Dorado	Vincent	235			21
112.3	Devil Canyon	Calectric	120			22
112.3	Devil Canyon	Calectric	120			23
Vol. 6, SA#33	Bailey Sub	Various	72			24
Vol. 6, SA#35	Bailey-Oso	Various	17			25
Vol. 6, SA#34	Pastoria-Pardee	Various	82			26
Vol. 6, SA#31	Edmonston-Pastoria	Vincent	787			27
Vol. 6, SA#32	Vincent	Various	152			28
339	Victorville-Lugo	Midway	150			29
403	Huntington Beach	Ellis				30
401	Mandalay	Santa Clara				31
402	Coolwater	Kramer				32
404	Ormond Beach	Moorpark				33
131	Mead	Mountain Center	10			34
			5,039	10,723,992	10,686,988	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred 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 (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Vol. 6, SA #11	Victor Substation	High Desert				1
470	Valley Sub	Inland Empire Energy				2
Vol. 5, SA #4	Victor / Vista Sub	Cottonwood/Zanja Sub	39	68,589	68,589	3
Vol. 5, SA #4	Victor / Vista Sub	Cottonwood/Zanja Sub	39	140,403	140,403	4
Vol. 5, SA #56	Vista	Cherry Valley Stn		118	118	5
Vol. 5, SA #56	Vista	Cherry Valley Stn		14,019	14,019	6
Vol. 5, SA #57	Vista	Crafton Hills Stn		2,958	2,958	7
Vol. 5, SA #57	Vista	Crafton Hills Stn		17,326	17,326	8
Vol. 6, SA #58	San Bernardino	Greenspot Station	4	2,322	2,322	9
Vol. 6, SA #58	San Bernardino	Greenspot Station	4	15,884	15,884	10
Vol. 6, SA #31	Vincent	Oso Pumping Plant	787	135,167	135,167	11
Vol. 6, SA #31	Vincent	Oso Pumping Plant	787	96,553	96,553	12
Vol. 6, SA #32	Edmonston-Pastoria	Pearblossom Pump Pnt	152	108,590	108,590	13
Vol. 6, SA #32	Edmonston-Pastoria	Pearblossom Pump Pnt	152	420,396	420,396	14
Vol. 6, SA #33	Bailey-Oso	Edmonstn Pmpng Plnt	72	549,831	549,831	15
Vol. 6, SA #33	Bailey-Oso	Edmonstn Pmpng Plnt	72	2,730,919	2,730,919	16
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		29,411	29,411	17
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		81,831	81,831	18
Vol. 5, SA 103	Valley Sub	Moreno Val Iris Ave	3	35,171	35,171	19
Vol. 5, SA 103	Valley Sub	Moreno Val Iris Ave	3	104,691	104,691	20
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		27,144	27,144	21
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		78,824	78,824	22
N/A	N/A	N/A				23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			5,039	10,723,992	10,686,988	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
194,947			194,947	1
605,000		159	605,159	2
55,202		15	55,217	3
167,348		51,472	218,820	4
14,123		4,679	18,802	5
		125,331	125,331	6
128,240			128,240	7
128,240			128,240	8
448,840			448,840	9
256,480			256,480	10
125,300			125,300	11
295,823		25,746	321,569	12
25,844		2,374	28,218	13
104,640			104,640	14
523,200			523,200	15
69,760			69,760	16
174,400			174,400	17
		-595	-595	18
		-2,982	-2,982	19
		-963	-963	20
		-349	-349	21
133,211			133,211	22
5,835			5,835	23
212,612		31,815	244,427	24
18,956		2,892	21,848	25
96,180			96,180	26
450,219			450,219	27
96,180			96,180	28
		-9,623	-9,623	29
577,080			577,080	30
1,281,672		16,191	1,297,863	31
1,346,520		6,493	1,353,013	32
384,720			384,720	33
5,001,360			5,001,360	34
57,240,518	0	4,257,564	61,498,082	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
961,800			961,800	1
296,028			296,028	2
13,640		81	13,721	3
1,240		7	1,247	4
49,663		80	49,743	5
3,627		7	3,634	6
49,286		889	50,175	7
3,905		81	3,986	8
122,684		57,858	180,542	9
9,742		5,260	15,002	10
12,925		84	13,009	11
1,175		8	1,183	12
500,240			500,240	13
32,500			32,500	14
224,400			224,400	15
		-1,529	-1,529	16
11,220		82	11,302	17
1,020		8	1,028	18
61,776		80	61,856	19
5,616		7	5,623	20
40,260		81	40,341	21
3,660		7	3,667	22
28,798		80	28,878	23
2,618		7	2,625	24
32,292		80	32,372	25
2,640		7	2,647	26
31,272		84	31,356	27
1,750		8	1,758	28
93,881		84	93,965	29
7,190		8	7,198	30
42,954		84	43,038	31
3,720		8	3,728	32
139,812		80	139,892	33
10,440		7	10,447	34
57,240,518	0	4,257,564	61,498,082	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
22,640		107	22,747	1
1,734		10	1,744	2
		-813	-813	3
		-3,072	-3,072	4
177,969		4,613	182,582	5
16,128		419	16,547	6
26,950		103	27,053	7
2,450		9	2,459	8
197,884		103	197,987	9
17,723		9	17,732	10
305,800		103	305,903	11
122,847		80	122,927	12
11,547		7	11,554	13
32,019		80	32,099	14
2,670		7	2,677	15
27,800		9	27,809	16
		3,743	3,743	17
85,260			85,260	18
11,798,080			11,798,080	19
151,200			151,200	20
2,820,000			2,820,000	21
43,200			43,200	22
3,600			3,600	23
		71,400	71,400	24
		35,472	35,472	25
		41,172	41,172	26
		93,972	93,972	27
		267,600	267,600	28
1,170,000			1,170,000	29
		399,766	399,766	30
		188,880	188,880	31
		945,874	945,874	32
		1,732,474	1,732,474	33
246,100			246,100	34
57,240,518	0	4,257,564	61,498,082	

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
		264,134	264,134	1
		42,492	42,492	2
		-2,952	-2,952	3
		-6,922	-6,922	4
		-4	-4	5
		-14	-14	6
		-83	-83	7
		-479	-479	8
		-64	-64	9
		-471	-471	10
		-294	-294	11
		-3,492	-3,492	12
		-3,109	-3,109	13
		-8,725	-8,725	14
		-14,007	-14,007	15
		-75,201	-75,201	16
		-2,023	-2,023	17
		-7,888	-7,888	18
		-2,593	-2,593	19
		-9,756	-9,756	20
		-1,917	-1,917	21
		-7,478	-7,478	22
24,231,211			24,231,211	23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
57,240,518	0	4,257,564	61,498,082	

Name of Respondent Southern California Edison Company	This Report is: (1) <u>X</u> An Original (2) <u> </u> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 328	Line No.: 1	Column: d	OLF - 2 Year Notice.
Schedule Page: 328	Line No.: 1	Column: h	Billing Demand 34.5
Schedule Page: 328	Line No.: 1	Column: i	N/A
Schedule Page: 328	Line No.: 1	Column: j	N/A
Schedule Page: 328	Line No.: 2	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 2	Column: m	Customer charge per agreement.
Schedule Page: 328	Line No.: 3	Column: m	Customer charge per agreement. Revenue received in current year for prior year's service period.
Schedule Page: 328	Line No.: 4	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 4	Column: h	Billing Demand 48.70
Schedule Page: 328	Line No.: 4	Column: m	Customer charge plus facility charge per agreement.
Schedule Page: 328	Line No.: 5	Column: h	Billing Demand 48.70
Schedule Page: 328	Line No.: 5	Column: m	Customer charge per agreement. Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.
Schedule Page: 328	Line No.: 6	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 6	Column: h	Billing Demand 48.70
Schedule Page: 328	Line No.: 6	Column: m	Customer charge plus facility charge per agreement.
Schedule Page: 328	Line No.: 7	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 7	Column: i	N/A
Schedule Page: 328	Line No.: 7	Column: j	N/A
Schedule Page: 328	Line No.: 8	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 8	Column: i	N/A
Schedule Page: 328	Line No.: 8	Column: j	N/A
Schedule Page: 328	Line No.: 9	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 9	Column: i	N/A
Schedule Page: 328	Line No.: 9	Column: j	N/A
Schedule Page: 328	Line No.: 10	Column: d	OLF - 1 Year Notice.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 328	Line No.: 10	Column: i	N/A
Schedule Page: 328	Line No.: 10	Column: j	N/A
Schedule Page: 328	Line No.: 11	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 11	Column: i	N/A
Schedule Page: 328	Line No.: 11	Column: j	N/A
Schedule Page: 328	Line No.: 12	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 12	Column: h	Billing Demand 36.40
Schedule Page: 328	Line No.: 12	Column: m	Customer charge plus facility charge per agreement.
Schedule Page: 328	Line No.: 13	Column: h	Billing Demand 36.40
Schedule Page: 328	Line No.: 13	Column: m	Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.
Schedule Page: 328	Line No.: 14	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 14	Column: i	N/A
Schedule Page: 328	Line No.: 14	Column: j	N/A
Schedule Page: 328	Line No.: 15	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 15	Column: i	N/A
Schedule Page: 328	Line No.: 15	Column: j	N/A
Schedule Page: 328	Line No.: 16	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 16	Column: i	N/A
Schedule Page: 328	Line No.: 16	Column: j	N/A
Schedule Page: 328	Line No.: 17	Column: d	OLF - 1 Year Notice.
Schedule Page: 328	Line No.: 17	Column: i	N/A
Schedule Page: 328	Line No.: 17	Column: j	N/A
Schedule Page: 328	Line No.: 18	Column: d	OLF - 180 Days Notice.
Schedule Page: 328	Line No.: 18	Column: h	Billing Demand 5.6
Schedule Page: 328	Line No.: 18	Column: m	Reliability Services Charge.
Schedule Page: 328	Line No.: 19	Column: h	

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Billing Demand 5.6

Schedule Page: 328 Line No.: 19 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328 Line No.: 20 Column: d

OLF - 180 Days Notice.

Schedule Page: 328 Line No.: 20 Column: h

Billing Demand 1.25

Schedule Page: 328 Line No.: 20 Column: m

Reliability Services Charge.

Schedule Page: 328 Line No.: 21 Column: h

Billing Demand 1.25

Schedule Page: 328 Line No.: 21 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328 Line No.: 22 Column: d

OLF - 180 Days Notice.

Schedule Page: 328 Line No.: 22 Column: h

Billing Demand 1.25

Schedule Page: 328 Line No.: 23 Column: h

Billing Demand 1.25

Schedule Page: 328 Line No.: 24 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 24 Column: h

Billing Demand 67.70

Schedule Page: 328 Line No.: 24 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328 Line No.: 25 Column: h

Billing Demand 67.70

Schedule Page: 328 Line No.: 25 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328 Line No.: 26 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 26 Column: i

N/A

Schedule Page: 328 Line No.: 26 Column: j

N/A

Schedule Page: 328 Line No.: 27 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 27 Column: h

Billing Demand 14.04

Schedule Page: 328 Line No.: 27 Column: i

N/A

Schedule Page: 328 Line No.: 27 Column: j

N/A

Schedule Page: 328 Line No.: 28 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 28 Column: i

N/A

Schedule Page: 328 Line No.: 28 Column: j

N/A

Schedule Page: 328 Line No.: 29 Column: d

OLF - 1 Year Notice.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 29 Column: e

FERC Rate Schedule: 361, 362, 363 and 365.

Schedule Page: 328 Line No.: 29 Column: h

Billing Demand N/A

Schedule Page: 328 Line No.: 29 Column: i

N/A

Schedule Page: 328 Line No.: 29 Column: j

N/A

Schedule Page: 328 Line No.: 29 Column: m

Reliability Services Charge.

Schedule Page: 328 Line No.: 30 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 30 Column: i

N/A

Schedule Page: 328 Line No.: 30 Column: j

N/A

Schedule Page: 328 Line No.: 31 Column: d

OLF - 1 Year Notice.

Schedule Page: 328 Line No.: 31 Column: h

Billing Demand N/A

Schedule Page: 328 Line No.: 31 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328 Line No.: 32 Column: d

OLF - 180 Days Notice.

Schedule Page: 328 Line No.: 32 Column: i

N/A

Schedule Page: 328 Line No.: 32 Column: j

N/A

Schedule Page: 328 Line No.: 32 Column: m

Interconnection Service Charges.

Schedule Page: 328 Line No.: 33 Column: d

OLF - 180 Days Notice.

Schedule Page: 328 Line No.: 33 Column: i

N/A

Schedule Page: 328 Line No.: 33 Column: j

N/A

Schedule Page: 328 Line No.: 34 Column: d

OLF - 180 Days Notice.

Schedule Page: 328 Line No.: 34 Column: i

N/A

Schedule Page: 328 Line No.: 34 Column: j

N/A

Schedule Page: 328.1 Line No.: 1 Column: d

OLF - 180 Days Notice.

Schedule Page: 328.1 Line No.: 1 Column: i

N/A

Schedule Page: 328.1 Line No.: 1 Column: j

N/A

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

OLF - 2 Years Notice.

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

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Billing Demand N/A

Schedule Page: 328.1 Line No.: 2 Column: i
N/A

Schedule Page: 328.1 Line No.: 2 Column: j
N/A

Schedule Page: 328.1 Line No.: 3 Column: d
OLF - 06/17/2036.

Schedule Page: 328.1 Line No.: 3 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 4 Column: m
Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 5 Column: d
OLF - 05-01-2034.

Schedule Page: 328.1 Line No.: 5 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 6 Column: m
Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 7 Column: d
OLF - 180 Days Notice.

Schedule Page: 328.1 Line No.: 7 Column: h
Billing Demand 3.28

Schedule Page: 328.1 Line No.: 7 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 8 Column: h
Billing Demand 3.28

Schedule Page: 328.1 Line No.: 8 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 9 Column: d
OLF - 180 Days Notice.

Schedule Page: 328.1 Line No.: 9 Column: h
Billing Demand 1.7

Schedule Page: 328.1 Line No.: 9 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 10 Column: h
Billing Demand 1.7

Schedule Page: 328.1 Line No.: 10 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 11 Column: d
OLF - 11/12/2034.

Schedule Page: 328.1 Line No.: 11 Column: h
Billing Demand 2.5

Schedule Page: 328.1 Line No.: 11 Column: m
Customer charge per agreement.

Schedule Page: 328.1 Line No.: 12 Column: h
Billing Demand 2.5

Schedule Page: 328.1 Line No.: 12 Column: m
Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 13 Column: d
OLF - Hoover PSC

Schedule Page: 328.1 Line No.: 13 Column: i
N/A

Schedule Page: 328.1 Line No.: 13 Column: j

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

N/A

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

N/A

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

N/A

Schedule Page: 328.1 Line No.: 15 Column: d

OLF - 12/31/2002 - Perm Removed From Service.

Schedule Page: 328.1 Line No.: 15 Column: i

N/A

Schedule Page: 328.1 Line No.: 15 Column: j

N/A

Schedule Page: 328.1 Line No.: 16 Column: d

OLF - Upon Notice.

Schedule Page: 328.1 Line No.: 16 Column: h

Billing Demand N/A

Schedule Page: 328.1 Line No.: 16 Column: i

N/A

Schedule Page: 328.1 Line No.: 16 Column: j

N/A

Schedule Page: 328.1 Line No.: 16 Column: m

Reliability Services Charge.

Schedule Page: 328.1 Line No.: 17 Column: d

OLF - 05/03/2037.

Schedule Page: 328.1 Line No.: 17 Column: m

Customer charge per agreement.

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

Customer charge per agreement. Revenue received in current year for prior year's service period.

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

OLF - 12/31/2032.

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

Billing Demand 7.2

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

Customer charge per agreement.

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

Billing Demand 7.2

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

Customer charge per agreement. Revenue received in current year for prior year's service period.

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

OLF - 10/03/2036.

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

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 22 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 23 Column: d

OLF - 04/11/2034.

Schedule Page: 328.1 Line No.: 23 Column: h

Billing Demand 1.4

Schedule Page: 328.1 Line No.: 23 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 24 Column: h

Billing Demand 1.4

Schedule Page: 328.1 Line No.: 24 Column: m

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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FOOTNOTE DATA			

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 25 Column: d

OLF - 11/13/2035.

Schedule Page: 328.1 Line No.: 25 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 26 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 27 Column: d

OLF - 03/05/2035.

Schedule Page: 328.1 Line No.: 27 Column: h

Billing Demand .5

Schedule Page: 328.1 Line No.: 27 Column: m

Customer charge per agreement.

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

Billing Demand .5

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

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 29 Column: d

OLF - 10/31/2034.

Schedule Page: 328.1 Line No.: 29 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 30 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.1 Line No.: 31 Column: d

OLF - 10/01/2034.

Schedule Page: 328.1 Line No.: 31 Column: h

Billing Demand 1.5

Schedule Page: 328.1 Line No.: 31 Column: m

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 32 Column: h

Billing Demand 1.5

Schedule Page: 328.1 Line No.: 32 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

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

OLF - 07/22/2037.

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

Customer charge per agreement.

Schedule Page: 328.1 Line No.: 34 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.2 Line No.: 1 Column: d

OLF - 07/21/2053.

Schedule Page: 328.2 Line No.: 1 Column: h

Billing Demand 3.867

Schedule Page: 328.2 Line No.: 1 Column: m

Customer charge per agreement.

Schedule Page: 328.2 Line No.: 2 Column: h

Billing Demand 3.867

Schedule Page: 328.2 Line No.: 2 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.2 Line No.: 3 Column: d

OLF - 180 Days Notice.

Schedule Page: 328.2 Line No.: 3 Column: h

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Billing Demand 7.2/2/2

Schedule Page: 328.2 Line No.: 3 Column: m

Reliability Services Charge.

Schedule Page: 328.2 Line No.: 4 Column: h

Billing Demand 7.2/2/2

Schedule Page: 328.2 Line No.: 4 Column: m

Reliability Service revenue received in current year for prior year's service.

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

OLF - 180 Days Notice.

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

Billing Demand 6.5 / 1.5 / 0.7

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

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.2 Line No.: 6 Column: h

Billing Demand 6.5 / 1.5 / 0.7

Schedule Page: 328.2 Line No.: 6 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.2 Line No.: 7 Column: d

OLF - Plant Life.

Schedule Page: 328.2 Line No.: 7 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 7 Column: m

Customer charge per agreement.

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

Billing Demand .5

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

Customer charge per agreement. Revenue received in current year for prior year's service period.

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

OLF - Plant Life.

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

Billing Demand 3.7

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

Customer charge per agreement.

Schedule Page: 328.2 Line No.: 10 Column: h

Billing Demand 3.7

Schedule Page: 328.2 Line No.: 10 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

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

OLF - Plant Life.

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

Customer charge per agreement.

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

OLF - 180 Days Notice.

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

Billing Demand 4.5

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

Customer charge per agreement.

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

Billing Demand 4.5

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

Customer charge per agreement.

Schedule Page: 328.2 Line No.: 14 Column: d

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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OLF - 06/01/2038.

Schedule Page: 328.2 Line No.: 14 Column: m

Customer charge per agreement.

Schedule Page: 328.2 Line No.: 15 Column: m

Customer charge per agreement.

Schedule Page: 328.2 Line No.: 16 Column: m

Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.2 Line No.: 17 Column: h

Billing Demand N/A

Schedule Page: 328.2 Line No.: 17 Column: i

N/A

Schedule Page: 328.2 Line No.: 17 Column: j

N/A

Schedule Page: 328.2 Line No.: 17 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328.2 Line No.: 18 Column: d

OLF - 08/04/2010.

Schedule Page: 328.2 Line No.: 18 Column: i

N/A

Schedule Page: 328.2 Line No.: 18 Column: j

N/A

Schedule Page: 328.2 Line No.: 19 Column: d

OLF - Term Service.

Schedule Page: 328.2 Line No.: 20 Column: d

OLF - Plant Life.

Schedule Page: 328.2 Line No.: 20 Column: i

N/A

Schedule Page: 328.2 Line No.: 20 Column: j

N/A

Schedule Page: 328.2 Line No.: 21 Column: d

OLF - 12/31/2020.

Schedule Page: 328.2 Line No.: 21 Column: i

N/A

Schedule Page: 328.2 Line No.: 21 Column: j

N/A

Schedule Page: 328.2 Line No.: 22 Column: d

OLF - Plant Life.

Schedule Page: 328.2 Line No.: 22 Column: i

N/A

Schedule Page: 328.2 Line No.: 22 Column: j

N/A

Schedule Page: 328.2 Line No.: 23 Column: i

N/A

Schedule Page: 328.2 Line No.: 23 Column: j

N/A

Schedule Page: 328.2 Line No.: 24 Column: d

OLF - 01/01/2035.

Schedule Page: 328.2 Line No.: 24 Column: i

N/A

Schedule Page: 328.2 Line No.: 24 Column: j

N/A

Schedule Page: 328.2 Line No.: 24 Column: m

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Interconnection Service Charges.

Schedule Page: 328.2 Line No.: 25 Column: d

OLF - 01/01/2035.

Schedule Page: 328.2 Line No.: 25 Column: i

N/A

Schedule Page: 328.2 Line No.: 25 Column: j

N/A

Schedule Page: 328.2 Line No.: 25 Column: m

Interconnection Service Charges.

Schedule Page: 328.2 Line No.: 26 Column: d

OLF - 01/01/2035.

Schedule Page: 328.2 Line No.: 26 Column: i

N/A

Schedule Page: 328.2 Line No.: 26 Column: j

N/A

Schedule Page: 328.2 Line No.: 26 Column: m

Interconnection Service Charges.

Schedule Page: 328.2 Line No.: 27 Column: d

OLF - 01/01/2035.

Schedule Page: 328.2 Line No.: 27 Column: i

N/A

Schedule Page: 328.2 Line No.: 27 Column: j

N/A

Schedule Page: 328.2 Line No.: 27 Column: m

Interconnection Service Charges.

Schedule Page: 328.2 Line No.: 28 Column: d

OLF - 01/01/2035.

Schedule Page: 328.2 Line No.: 28 Column: i

N/A

Schedule Page: 328.2 Line No.: 28 Column: j

N/A

Schedule Page: 328.2 Line No.: 28 Column: m

Interconnection Service Charges.

Schedule Page: 328.2 Line No.: 29 Column: d

OLF - 5 Year Notice.

Schedule Page: 328.2 Line No.: 29 Column: i

N/A

Schedule Page: 328.2 Line No.: 29 Column: j

N/A

Schedule Page: 328.2 Line No.: 30 Column: d

OLF - 12/31/2003 - Customer Terminated

Schedule Page: 328.2 Line No.: 30 Column: h

Billing Demand N/A

Schedule Page: 328.2 Line No.: 30 Column: i

N/A

Schedule Page: 328.2 Line No.: 30 Column: j

N/A

Schedule Page: 328.2 Line No.: 30 Column: m

Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.2 Line No.: 31 Column: d

OLF - 12/31/2004 - Take Service.

Schedule Page: 328.2 Line No.: 31 Column: h

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Billing Demand N/A

Schedule Page: 328.2 Line No.: 31 Column: i
N/A

Schedule Page: 328.2 Line No.: 31 Column: j
N/A

Schedule Page: 328.2 Line No.: 31 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.2 Line No.: 32 Column: d
OLF - 12/31/2023 Take Service.

Schedule Page: 328.2 Line No.: 32 Column: h
Billing Demand N/A

Schedule Page: 328.2 Line No.: 32 Column: i
N/A

Schedule Page: 328.2 Line No.: 32 Column: j
N/A

Schedule Page: 328.2 Line No.: 32 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement. Difference \$709.34 between G/L #4198114 & #4198122 one G/L is over and other is short. To be corrected in a future month.

Schedule Page: 328.2 Line No.: 33 Column: d
OLF - 12/31/2007 - Take Service.

Schedule Page: 328.2 Line No.: 33 Column: h
Billing Demand N/A

Schedule Page: 328.2 Line No.: 33 Column: i
N/A

Schedule Page: 328.2 Line No.: 33 Column: j
N/A

Schedule Page: 328.2 Line No.: 33 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.2 Line No.: 34 Column: d
OLF - 10 Year Notice.

Schedule Page: 328.2 Line No.: 34 Column: i
N/A

Schedule Page: 328.2 Line No.: 34 Column: j
N/A

Schedule Page: 328.3 Line No.: 1 Column: d
OLF - 30 Days Notice.

Schedule Page: 328.3 Line No.: 1 Column: h
Billing Demand N/A

Schedule Page: 328.3 Line No.: 1 Column: i
N/A

Schedule Page: 328.3 Line No.: 1 Column: j
N/A

Schedule Page: 328.3 Line No.: 1 Column: m
Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

Schedule Page: 328.3 Line No.: 2 Column: d
OLF - 30 Days Notice.

Schedule Page: 328.3 Line No.: 2 Column: h
Billing Demand N/A

Schedule Page: 328.3 Line No.: 2 Column: i
N/A

Schedule Page: 328.3 Line No.: 2 Column: j

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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N/A

Schedule Page: 328.3 Line No.: 2 Column: m

Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

Schedule Page: 328.3 Line No.: 3 Column: d

OLF - 30 Days Notice.

Schedule Page: 328.3 Line No.: 3 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 4 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 5 Column: d

OLF - Plant Life.

Schedule Page: 328.3 Line No.: 5 Column: h

Billing Demand .5

Schedule Page: 328.3 Line No.: 5 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 6 Column: h

Billing Demand .5

Schedule Page: 328.3 Line No.: 6 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 7 Column: d

OLF - Plant Life.

Schedule Page: 328.3 Line No.: 7 Column: h

Billing Demand 3.7

Schedule Page: 328.3 Line No.: 7 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 8 Column: h

Billing Demand 3.7

Schedule Page: 328.3 Line No.: 8 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 9 Column: d

OLF - Plant Life.

Schedule Page: 328.3 Line No.: 9 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 10 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 11 Column: d

OLF - 01/01/2035.

Schedule Page: 328.3 Line No.: 11 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 12 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 13 Column: d

OLF - 01/01/2035.

Schedule Page: 328.3 Line No.: 13 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 14 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 15 Column: d

OLF - 01/01/2035.

Schedule Page: 328.3 Line No.: 15 Column: m

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
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Reliability Services Charge.

Schedule Page: 328.3 Line No.: 16 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 17 Column: d

OLF - 30 Days Notice.

Schedule Page: 328.3 Line No.: 17 Column: h

Billing Demand 1.7

Schedule Page: 328.3 Line No.: 17 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 18 Column: h

Billing Demand 1.7

Schedule Page: 328.3 Line No.: 18 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 19 Column: d

OLF - 04/11/2034.

Schedule Page: 328.3 Line No.: 19 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 20 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 21 Column: d

OLF - 07/21/2053.

Schedule Page: 328.3 Line No.: 21 Column: h

Billing Demand 3.87

Schedule Page: 328.3 Line No.: 21 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 22 Column: h

Billing Demand 3.87

Schedule Page: 328.3 Line No.: 22 Column: m

Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 23 Column: d

OS - Plant Life.

Schedule Page: 328.3 Line No.: 23 Column: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 23 Column: i

N/A

Schedule Page: 328.3 Line No.: 23 Column: j

N/A

Schedule Page: 328.3 Line No.: 23 Column: k

Edison's share of statewide wheeling collected by the CAISO from scheduling coordinators.

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or “true-ups” for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tariff (d)	Total Revenue (e)
1	NONE				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

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			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Arizona Public Service	OLF	4,737,430	4,737,430			16,314,946	16,314,946
2	Company (APS)							
3	Western Area Power Admn	OLF						
4	- (Western)							
5	Western Area Power Admn	OLF					45,597	45,597
6	- (Western) - Blythe							
7	L.A. Dept of Water&Pwr	OLF					279,936	279,936
8	Imperial Irrigation Dis	FNS						
9	(Salton Sea)							
10								
11								
12								
13								
14								
15								
16								
	TOTAL		4,737,430	4,737,430			16,640,479	16,640,479

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 1 Column: b

OLF - 07/31/2014.

Schedule Page: 332 Line No.: 1 Column: g

APS - Operation and Maintenance Charges	- \$ 4,014,946
Property Taxes - Arizona & New Mexico	- \$ 0.
Hulapai Tribal Possessory Interest Tax Navajo Nation - Southern California	- \$ 0.
Edison Business Activity Tax Settlement Payment	- \$ 0.
Arizona Public Service Right of Way Indian Settlement	- \$12,300,000.

Schedule Page: 332 Line No.: 3 Column: b

Footnote Linked. See note on 332, Row: 1, col/item:

Schedule Page: 332 Line No.: 5 Column: b

OLF - 1 Year notice.

Schedule Page: 332 Line No.: 5 Column: g

Common Facilities Operations and Maintenance Charges \$45,597.

Schedule Page: 332 Line No.: 7 Column: b

OLF - 05/31/2025.

Schedule Page: 332 Line No.: 7 Column: g

Transmission Service Charge to SCE (Contract 10036) \$279,936.

Schedule Page: 332 Line No.: 8 Column: g

Scheduling, Transmission Service and Dispatching Fees.

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,583,461
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,027,741
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,152,360
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	
6	Credit Line Fees / Bank Charges	4,810,730
7	Directors' Fees and Expenses	3,172,431
8	Periodic SEC Reports	294,989
9	Planning and Development of Communication Systems	123,491
10	Consultants/Professional Services	2,298,651
11	Paid Absence Allocation Reclass	-3,205,340
12	Write-off of Abandoned Projects	5,265,051
13	Miscellaneous (Various Items)	31,921
14	Administrative and General Expense Charged or Paid -	-4,863,977
15	by others	
16		
17		
18		
19		
20		
21		
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45		
46	TOTAL	14,691,509

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition 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			134,241,083	732,354	134,973,437
2	Steam Production Plant	25,576,561			8,825,521	34,402,082
3	Nuclear Production Plant	55,522,327			57,538,268	113,060,595
4	Hydraulic Production Plant-Conventional	19,579,198				19,579,198
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	39,014,420				39,014,420
7	Transmission Plant	150,713,522			854,062	151,567,584
8	Distribution Plant	624,054,737				624,054,737
9	Regional Transmission and Market Operation					
10	General Plant	140,992,085			743,360	141,735,445
11	Common Plant-Electric	7,960				7,960
12	TOTAL	1,055,460,810		134,241,083	68,693,565	1,258,395,458

B. Basis for Amortization Charges

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION		45.00				
13	311	21,657	45.00		-2.17	Life Span	8.00
14	312	453,026	45.00	-0.50	2.07	Life Span	7.90
15	314	63,009	45.00	-0.60	3.87	Life Span	7.90
16	315	17,066	45.00	-0.40	4.05	Life Span	7.80
17	316	25,436	45.00		6.28	Life Span	8.00
18							
19							
20	NUCLEAR PRODUCTION						
21	SONGS 2 & 3						
22	321	85,743	39.00		0.49	Life Span	15.40
23	322	136,229	39.00		0.42	Life Span	15.40
24	323	38,380	39.00		0.65	Life Span	14.80
25	324	36,824	39.00		0.51	Life Span	15.50
26	325	104,192	39.00		2.15	Life Span	15.00
27							
28							
29	PVNGS 1,2 & 3						
30	321	13,219	39.00		0.70	Life Span	19.00
31	322	147,555	39.00		0.92	Life Span	18.90
32	323	57,875	39.00		1.06	Life Span	18.10
33	324	1,897	39.00		0.53	Life Span	19.10
34	325	12,822	39.00		-1.39	Life Span	18.20
35							
36							
37	HYDRAULIC						
38	331	125,841	61.00	-25.30	2.63	Life Span	38.90
39	332	452,807	73.00	-2.90	1.74	Life Span	40.00
40	333	129,896	59.00	-3.60	1.99	Life Span	39.20
41	334	134,320	43.00	-26.90	3.97	Life Span	34.00
42	335	11,366	58.00	-5.80	3.38	Life Span	40.70
43	336	10,470	66.00	-14.10	6.84	Life Span	35.70
44							
45							
46	OTHER PRODUCTION						
47	341	58,048	45.00		3.55	Life Span	24.70
48	342	10,715	45.00		5.46	Life Span	24.70
49	343	765,357	45.00		2.83	Life Span	24.70
50	344	85,161	45.00		2.85	Life Span	24.70

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	345	154,764	45.00		2.69	Life Span	24.70
13	346	4,304	45.00		3.57	Life Span	24.70
14							
15							
16	TRANSMISSION PLANT						
17	352	296,917	55.00	-40.00	2.50	S 3.0	39.30
18	353	3,180,474	40.00	5.00	2.54	R 1.0	31.60
19	354	675,240	65.00	-70.00	2.41	S 3.0	37.30
20	355	517,954	45.00	-70.00	3.90	R 1.0	35.80
21	356	614,853	50.00	-80.00	3.61	R 4.0	25.60
22	357	42,768	55.00		1.69	R 3.0	40.70
23	358	175,962	35.00	-30.00	3.87	R 3.0	24.60
24	359	31,913	60.00		1.70	SQ	32.10
25							
26							
27	DISTRIBUTION PLANT						
28	361	399,411	40.00	-20.00	3.15	S 2.0	25.50
29	362	1,457,056	45.00	-10.00	2.90	R 1.0	34.40
30	364	1,538,474	45.00	-190.00	7.05	R 0.5	36.90
31	365	1,049,690	45.00	-100.00	4.26	R 0.5	34.80
32	366	1,301,069	55.00	-20.00	2.16	R 3.0	40.80
33	367	3,764,680	30.00	-60.00	4.88	R 2.0	21.60
34	368	2,701,301	30.00		4.32	S 3.0	18.80
35	369	1,089,181	35.00	-75.00	5.43	R 2.0	24.00
36	370	757,651	30.00	-10.00	4.46	R 2.0	19.20
37	373	708,425	35.00	-15.00	3.01	L 0.5	26.80
38							
39							
40	GENERAL						
41	390	604,599	40.00	-5.00	1.62	R2.5	25.80
42	391.XXX	579,646	10.00		12.24	Judgement	3.02
43	392.4	3,272	7.00		14.29	Judgement	1.00
44	393	10,237	20.00		5.00	Judgement	7.70
45	394.6	221	10.00		10.00	Judgement	8.70
46	395	70,511	15.00		6.67	Judgement	6.70
47	397	423,379	15.00		11.34	Judgement	6.20
48	398	14,912	20.00		5.00	Judgement	7.80
49							
50	TOTAL	25,167,775					

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 336 Line No.: 7 Column: e
Includes account 108.105 (Plant held for future use) Accum. Depreciation for Easment/Land Rights.

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	Regulatory Commission Assessed Expenses				
2					
3	I.09-01-018; R.08-11-005				
4	2007 MALIBU CANYON FIRE OII (LA2009000172)		549,701	549,701	
5					
6	RP 08-426				
7	2008 FERC GRC - EL PASO TY (LA2008000756)		307,119	307,119	
8					
9	A.09-04-009				
10	2009 NDCTP (PROCEEDING) (LA2008001052)		403	403	
11					
12	A.09-12-024				
13	2009 RATE DESIGN WINDOW APPLICATION		24	24	
14	(LA2009001614)				
15					
16	A.08-06-001;A.08-06-002; A.08-06-003;				
17	D.09-08-027; G043088				
18	2009-2011 DEMAND RESPONSE APPLICATION		150	150	
19	(LA2008000311)				
20					
21	P.10-08-016				
22	2010 WMA PETITION FOR OIR (LA2010000804)		13,425	13,425	
23					
24	A.09-12-020				
25	2011 PG&E GENERAL RATE CASE (LA2010000056)		8,277	8,277	
26					
27	BP-12				
28	2012 BPA RATE CASE (LA2010000539)		72,147	72,147	
29					
30	A.10-11-015				
31	2012 GENERAL RATE CASE (LA2009000782)		427,651	427,651	
32					
33	EL10-64; EL 10-66; R.08-06-024				
34	AB 1613 OIR (LA2008000558)		101,617	101,617	
35					
36					
37	A.08-06-001; A.10-06-XXX				
38	APP FOR SCE SUMMER DISCOUNT PLAN PROG		54	54	
39	(LA2010000520)				
40					
41					
42	QM09-XX				
43	APPLICATION FOR RELIEF FROM PURPA PURCH		4,844	4,844	
44	(LA2009000724)				
45					
46	TOTAL		16,887,995	16,887,995	

REGULATORY COMMISSION EXPENSES

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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	A.09-04-002; D.10-07-049				
2	APRIL 2008 ERRA REASONABLENESS		1,050	1,050	
3	(LA2008000177)				
4					
5	A.10-04-002				
6	APRIL 2010 ERRA REASONABLENESS PROC		108,046	108,046	
7	(LA2010000050)				
8					
9	A.10-08-001				
10	AUGUST 2010 ERRA FORECAST APPLICATION		144	144	
11	(LA2010000595)				
12					
13	R.04-04-003; R.04-04-025				
14	AVOIDED COST OIR (LA2004000701)		174,526	174,526	
15					
16	Various				
17	CAISO TARIFF AMENDMENTS (LA2005000863)		124	124	
18					
19	07-157C, 07-167C				
20	CALIFORNIA MUNI LITIGATION (LA2006000235)		-1,833,382	-1,833,382	
21					
22	EL09-65				
23	CARE COMPLAINT Vs. CPUC, SCE, & CAISO		3,349	3,349	
24	(LA2009000726)				
25					
26	No Docket				
27	CASE ADMINISTRATION EXPENSE (LA1996000170)		1,958	1,958	
28					
29	A.08-07-021; D.09-09-047				
30	CEES - CUSTOMER ENERGY EFF & SOLAR GRP		420	420	
31	(LA2010000646)				
32					
33	A.09-11-011				
34	CEMA 2007-2008 BARK BEETLE (LA2009000730)		32	32	
35					
36	A.04-12-003, A.10-04-026, D.05-08-039				
37	CEMA-2007 WIND AND FIRESTORMS (LA2007000881)		33,262	33,262	
38					
39	No Docket				
40	CPUC APP FOR AUTH RENEW SONGS 2 & 3 NRC		4,468	4,468	
41	(LA2007000327)				
42					
43	ALJ-260				
44	CPUC RESOLUTION ALJ-260 (LA2010000914)		4,684	4,684	
45					
46	TOTAL		16,887,995	16,887,995	

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	ER10-160				
2	CWIP - 2009 (LA2009001053)		51,153	51,153	
3					
4	ER11-1952				
5	CWIP - 2011 (LA2010000837)		10,862	10,862	
6					
7	C.09-11-003				
8	DAVIS-STIRLING (426 MILLS WAY) Vs. SCE		42	42	
9	(LA2009001619)				
10					
11	R.07-05-025				
12	DIRECT ACCESS RESTORATION OIR (LA2007000370)		344	344	
13					
14	No Docket				
15	DMM ISSUES (LA2008000389)		698	698	
16					
17	R.06-07-010, R.09-06-018				
18	DWR REV REQUIRE DETERMINATION		63	63	
19	(LA2006000299)				
20					
21	No Docket				
22	E&I OF ALLEGATIONS BY RICHARD GIROUX		37,071	37,071	
23	(LA2010000546)				
24					
25	A.04-04-008, A.09-10-012, D.10-06-015				
26	ECONOMIC DEVELOPMENT RATE APPL		224	224	
27	(LA2004000330)				
28					
29	EL10-1				
30	EITP INCENTIVES APPLICATION (LA2009000719)		90,636	90,636	
31					
32	A.10-XX-XXX				
33	FALCON RIDGE SUBSTATION PROJ (ARRA)		3,652	3,652	
34	(LA2010000569)				
35					
36	EL00-95-000, EL00-98-000				
37	FERC INVESTIGATION (LA2000000853)		5,696,757	5,696,757	
38					
39	ER08-1343, etc.				
40	FERC RATES AND TRANSMISSION INCENTIVES		85,155	85,155	
41	(LA2006000713)				
42					
43	RM07-1				
44	FERC STANDARDS OF CONDUCT (LA2004000567)		-4,953	-4,953	
45					
46	TOTAL		16,887,995	16,887,995	

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	ER09-1534				
2	FERC TRANS RATE CASE - 2010 (LA2009000555)		457,418	457,418	
3					
4	C.09-12-006				
5	HAMILTON COVE COMPLAINT (LA2010000044)		78	78	
6					
7	A.904-008				
8	HECA (LA2008000801)		101,125	101,125	
9					
10	No Docket				
11	INTERCONNECTION ISSUES (LA2008000697)		95,762	95,762	
12					
13	A.06-08-011, D.07-03-013, EL11-8, EL11-11				
14	ISO/TO/RTO/VARIOUS TRANS & MKT ISSUES (LA2006000712)		61,900	61,900	
15					
16					
17	A.07-10-005, A.09-02-012, A.10-XX-XXX,				
18	D.09-04-006, P-11858				
19	LEAPS CPCN (NEVADA HYDRO) (LA2007000850)		671	671	
20					
21	C.10-07-008, D.11-01-006				
22	METRO WATER COMPLAINT (LA2010000690)		48	48	
23					
24	No Docket				
25	MISC. RELIABILITY ISSUES (LA2007000712)		41,580	41,580	
26					
27	No Docket				
28	MOHAVE CO-TENANCY AGREEMENT (LA2010000846)		1,432	1,432	
29					
30	No Docket				
31	MULTI-CLIENT GEN NUCLEAR (LA1994000005)		23,385	23,385	
32					
33	A.09-09-015				
34	MVPP NOVATION (LA2009000744)		120	120	
35					
36	No Docket				
37	NRC APPLICATION RENEWING SONGS 2 & 3 NRC (LA2007000666)		56,778	56,778	
38					
39					
40	No Docket				
41	NRC GEN. LICENSING MTR (LA1992000676)		119,592	119,592	
42					
43	No Docket				
44	NRC OI ON FIREWATCH SPECIALIST FAILURE (LA2007000872)		4,806	4,806	
45					
46	TOTAL		16,887,995	16,887,995	

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	No Docket				
2	NRC SCAFFOLDING INVESTIGATION (LA2010000490)		12,695	12,695	
3					
4	A.10-03-013				
5	NSCR (NET SURPLUS COMP RATE) (BK)		222	222	
6	(LA2010000140)				
7					
8	R.08-02-007				
9	OIR 2008 LONG-TERM PROCURMENT PLANS		283	283	
10	(LA2008000178)				
11					
12	R.08-11-005				
13	OIR R.08-11-005 REVISE & CLARIFY COM REG		380	380	
14	(LA2008000942)				
15					
16	04-DIST-GEN-01, R.06-03-004, R.08-03-008				
17	OIR RE DISTRIBUTED GENERATION (LA2006000260)		170	170	
18					
19	A.07-01-026, A.07-01-029, A.07-01-030				
20	D.10-04-030 , R.06-04-010				
21	OIR RE ENERGY EFFICIENCY POLICIES, ETC.		283	283	
22	(LA2006000581)				
23					
24	R.09-07-027				
25	OIR TO AMEND G.O. 156 (LA2009000747)		430	430	
26					
27	R.09-04-012				
28	OIR/SRP WATER & SEWER COMPANIES		90	90	
29	(LA2009000570)				
30					
31	A.05-06-015				
32	ON-BILL FINANCING (LA2005000837)		2,528	2,528	
33					
34	R.08-03-009				
35	P.U. CODE 399.2.5 ISSUES (LA2010000218)		72,031	72,031	
36					
37	A.03-XX-XXX				
38	PALM DESERT APPLICATION (LA2010000138)		276	276	
39					
40	D.09-05-027, I.06-06-014				
41	PBR OII (LA2006000583)		466	466	
42					
43	A.10-03-014				
44	PG&E 2011 GRC, PHASE 2 (LA2010000386)		6,158	6,158	
45					
46	TOTAL		16,887,995	16,887,995	

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	A.10-01-014				
2	PG&E 3D SEISMIC (LA2010000082)		43	43	
3					
4	A.10-02-012				
5	PG&E FEBRUARY 2010 ERRA REVIEW APPL. (LA2010000317)		216	216	
6					
7					
8	A.10-01-022				
9	PG&E LICENSE RENEWAL (LA2010000083)		80	80	
10					
11	A.09-04-007				
12	PG&E'S NDCTP 2009 FILING (LA2009000382)		216	216	
13					
14	No Docket				
15	RENEWABLE PROCUREMENT AGMNTS (LA2002000707)		102,656	102,656	
16					
17					
18	No Docket				
19	RETROACTIVE RATEMAKING REVIEW (LA2010000744)		2,779	2,779	
20					
21					
22	RM10-23				
23	ROFR NOPR (LA2010000526)		30,182	30,182	
24					
25	03-RPS-1078, A.09-10-035, A.10-03-XXX,				
26	B206516, R.04-04-026, R.06-02-012,				
27	R.06-05-027, R.08-08-009				
28	RPS OIR (LA2006000240)		1,958	1,958	
29					
30	No Docket				
31	SAN FRANCISCO OFFICE (LA2004001099)		1,325	1,325	
32					
33	A.09-08-019				
34	SDG&E's Z-FACTOR APPLICATION (LA2010000005)		1,644	1,644	
35					
36	PL09-4, R.08-12-009				
37	SMART GRID OIR (LA2008001064)		57,520	57,520	
38					
39	A.07-07-026, D.08-09-039				
40	SMARTCONNECT (LA2007000393)		120	120	
41					
42	A.10-03-028				
43	SOCALGAS' FAR UPDATE APPLICATION (LA2010000285)		93	93	
44					
45					
46	TOTAL		16,887,995	16,887,995	

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	C.09-11-009, D.10-11-001				
2	SOLOMAN, PETER DBA REGENCY HOMES Vs. SCE		414	414	
3	(LA2009001615)				
4					
5	C.10-01-001				
6	SOLUTIONS FOR UTILITIES Vs. SCE (LA2010000079)		228	228	
7					
8	No Docket				
9	SONGS 2010 TRIENNIAL FIRE INSPECTION		147,279	147,279	
10	(LA2010000502)				
11					
12	No Docket				
13	SONGS GRC POLICY TESTIMONY (LA2010000867)		19,445	19,445	
14					
15	No Docket				
16	SONGS OPERATOR ROUND INVESTIGATION		20,694	20,694	
17	(LA2010000272)				
18					
19	No Docket				
20	SONGS PERFORMANCE IMPROVEMENT ADVICE		1,836,982	1,836,982	
21	(LA2009000415)				
22					
23	No Docket				
24	SONGS POLAR CRANE INVESTIGATION		20,911	20,911	
25	(LA2010000217)				
26					
27	USCA 05-1327 & 1331				
28	STATION POWER APPEAL (LA2005000952)		164,103	164,103	
29					
30	05-1327, 08-1384				
31	STATION POWER TARIFF (LA2008000691)		3,763	3,763	
32					
33	No Docket				
34	TELECOM REGULATORY ADVICE (LA2009001596)		2,975	2,975	
35					
36	EL11-XX (101119-01)				
37	TRANS. INCENTIVES PETITION FOR D.O 11/10		54,880	54,880	
38	(LA2010000783)				
39					
40	EL10-81				
41	TRANS. INCENTIVES PETITION FOR DEC ORDER		41,797	41,797	
42	(LA2010000530)				
43					
44	No Docket				
45	TRANSCRIPTS-CPUC (ONLY) (LA1990000067)		3,065	3,065	
46	TOTAL		16,887,995	16,887,995	

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	ER10-1401, ER10-2191				
2	TRANSMISSION PLANNING ISSUES (LA2009001648)		3,352	3,352	
3					
4	A.09-08-020				
5	WILDFIRE TASK FORCE (LA2009000177)		266,813	266,813	
6					
7	No Docket				
8	WORK HOUR RULE INVESTIGATION (LA2010000482)		155,353	155,353	
9					
10	Procurement/Equipment Services		8,505	8,505	
11	OPERA PLAZA HOMEOWNERS ASSN		100	100	
12					
13					
14					
15					
16					
17					
18					
19	REGULATORY COMMISSION EXPENSES:				
20	ISO FERC Fees- Corporate & Regulatory Acctng		5,680,256	5,680,256	
21	INTERVENOR COMPENSATION		1,206,637	1,206,637	
22					
23					
24					
25	EMPLOYEE SALARIES AND EXPENSES RELATED TO				
26	FORMAL CASES:				
27	FERC Applications				
28	Minor Items (Less than \$25,000.)		35,107	35,107	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		16,887,995	16,887,995	

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
							2
							3
ELECTRIC	928	549,701					4
							5
							6
ELECTRIC	928	307,119					7
							8
							9
ELECTRIC	928	403					10
							11
							12
ELECTRIC	928	24					13
							14
							15
							16
							17
ELECTRIC	928	150					18
							19
							20
							21
ELECTRIC	928	13,425					22
							23
							24
ELECTRIC	928	8,277					25
							26
							27
ELECTRIC	928	72,147					28
							29
							30
ELECTRIC	928	427,651					31
							32
							33
ELECTRIC	928	101,617					34
							35
							36
							37
ELECTRIC	928	54					38
							39
							40
							41
							42
ELECTRIC	928	4,844					43
							44
							45
		16,887,995					46

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	51,153					2
							3
							4
ELECTRIC	928	10,862					5
							6
							7
ELECTRIC	928	42					8
							9
							10
							11
ELECTRIC	928	344					12
							13
							14
ELECTRIC	928	698					15
							16
							17
ELECTRIC	928	63					18
							19
							20
							21
ELECTRIC	928	37,071					22
							23
							24
							25
ELECTRIC	928	224					26
							27
							28
							29
ELECTRIC	928	90,636					30
							31
							32
ELECTRIC	928	3,652					33
							34
							35
							36
ELECTRIC	928	5,696,757					37
							38
							39
ELECTRIC	928	85,155					40
							41
							42
							43
ELECTRIC	928	-4,953					44
							45
		16,887,995					46

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	457,418					2
							3
							4
ELECTRIC	928	78					5
							6
							7
ELECTRIC	928	101,125					8
							9
							10
ELECTRIC	928	95,762					11
							12
							13
ELECTRIC	928	61,900					14
							15
							16
							17
							18
ELECTRIC	928	671					19
							20
							21
ELECTRIC	928	48					22
							23
							24
ELECTRIC	928	41,580					25
							26
							27
ELECTRIC	928	1,432					28
							29
							30
ELECTRIC	928	23,385					31
							32
							33
ELECTRIC	928	120					34
							35
							36
ELECTRIC	928	56,778					37
							38
							39
							40
ELECTRIC	928	119,592					41
							42
							43
ELECTRIC	928	4,806					44
							45
							45
		16,887,995					46

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	12,695					2
							3
							4
ELECTRIC	928	222					5
							6
							7
							8
ELECTRIC	928	283					9
							10
							11
							12
ELECTRIC	928	380					13
							14
							15
							16
ELECTRIC	928	170					17
							18
							19
							20
ELECTRIC	928	283					21
							22
							23
							24
ELECTRIC	928	430					25
							26
							27
ELECTRIC	928	90					28
							29
							30
							31
ELECTRIC	928	2,528					32
							33
							34
ELECTRIC	928	72,031					35
							36
							37
ELECTRIC	928	276					38
							39
							40
ELECTRIC	928	466					41
							42
							43
ELECTRIC	928	6,158					44
							45
							45
		16,887,995					46

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	43					2
							3
							4
ELECTRIC	928	216					5
							6
							7
							8
ELECTRIC	928	80					9
							10
							11
ELECTRIC	928	216					12
							13
							14
ELECTRIC	928	102,656					15
							16
							17
							18
ELECTRIC	928	2,779					19
							20
							21
							22
ELECTRIC	928	30,182					23
							24
							25
							26
							27
ELECTRIC	928	1,958					28
							29
							30
ELECTRIC	928	1,325					31
							32
							33
ELECTRIC	928	1,644					34
							35
							36
ELECTRIC	928	57,520					37
							38
							39
ELECTRIC	928	120					40
							41
							42
ELECTRIC	928	93					43
							44
							45
		16,887,995					46

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				Line No.
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	414					2
							3
							4
							5
ELECTRIC	928	228					6
							7
							8
ELECTRIC	928	147,279					9
							10
							11
							12
ELECTRIC	928	19,445					13
							14
							15
ELECTRIC	928	20,694					16
							17
							18
							19
ELECTRIC	928	1,836,982					20
							21
							22
							23
ELECTRIC	928	20,911					24
							25
							26
							27
ELECTRIC	928	164,103					28
							29
							30
ELECTRIC	928	3,763					31
							32
							33
ELECTRIC	928	2,975					34
							35
							36
ELECTRIC	928	54,880					37
							38
							39
							40
ELECTRIC	928	41,797					41
							42
							43
							44
ELECTRIC	928	3,065					45
							46
		16,887,995					46

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 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
Department (f)	Account No. (g)	Amount (h)					
							1
ELECTRIC	928	3,352					2
							3
							4
ELECTRIC	928	266,813					5
							6
							7
ELECTRIC	928	155,353					8
							9
ELECTRIC	928	8,505					10
ELECTRIC	928	100					11
							12
							13
							14
							15
							16
							17
							18
							19
ELECTRIC	928	5,680,256					20
ELECTRIC	928	1,206,637					21
							22
							23
							24
							25
							26
							27
ELECTRIC	928	35,107					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		16,887,995					46

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).

2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1	A. Environmental Health & Safety	
2		EPRI Global Climate Policy - P102
3		EPRI Greenhouse Gas Reduction - P103
4		EPRI Occupational Health and Safety Target
5		EPRI 60A - EMF Health Assessment: Community & Residential
6		Cloud Seeding Evaluation and Optimization
7		Improving Load Temperature Forecasts
8		
9		
10	B. Transmission and Distribution (T&D)	
11	(1) Transmission	PMU-Enabled Voltage And Var Control Demo
12		FREEDM Project
13		PSERC - Power Systems Engineering Research Center
14		EPRI PROG 172A - Efficient Transmission Systems
15		
16		
17	(2) Distribution	EPRI Smart Grid Demonstration
18		Delta Storage
19		Load Assessment Projects (GC16)
20		Smart Grid Information Integration Demonstation with
21		Cal Tech (System of Systems)
22		RTM Forum
23		EMP/GMD Hardening (NEW 27)
24		EPRI Program 161A - Intelligrid / Standards
25		CEC PIER Pathway to the Y2020 CA Smart Grid (with EPRI)
26		Wind/Solar Data Collection and Dynamic Model Validation
27		Real Time Digital Simulator (RTDS) Analysis of High Penetration
28		of Renewable Energy Resources
29		Infrastructure for Intelligent Distribution Systems - EPRI 161C
30		Test of Residential PV Inverters (Phase 2b)
31		Solar PV Readiness Phase 1
32		
33		
34		
35	C. Regional Transmission and Market Operation	Real Time Grid Monitoring
36		
37		
38	D. Customer Service / End Use	Incorporating PV into the Zero Net Energy Laboratory

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects. (Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

- | | |
|--|--|
| A. Electric R, D & D Performed Internally: | a. Overhead |
| (1) Generation | b. Underground |
| a. hydroelectric | (3) Distribution |
| i. Recreation fish and wildlife | (4) Regional Transmission and Market Operation |
| ii Other hydroelectric | (5) Environment (other than equipment) |
| b. Fossil-fuel steam | (6) Other (Classify and include items in excess of \$50,000.) |
| c. Internal combustion or gas turbine | (7) Total Cost Incurred |
| d. Nuclear | B. Electric, R, D & D Performed Externally: |
| e. Unconventional generation | (1) Research Support to the electrical Research Council or the Electric Power Research Institute |
| f. Siting and heat rejection | |
| (2) Transmission | |

Line No.	Classification (a)	Description (b)
1		
2		LED Street Light Demonstration
3		Wastewater Efficiency
4		TESLA Community Energy Storage (CES) PRG
5		EPRI Electric Vehicle Program 18
6		EPRI Energy Storage Program 94
7		PEV Integration and Communications
8		
9		
10	E. Support	Research Administration and Project Development
11		Integrate Lotus Connection with Opentext ECM
12		Cloud Computing and Virtualization - System Test Environments
13		
14		
15		
16		
17		
18	Total Research and Development	
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
- (3) Research Support to Nuclear Power Groups
- (4) Research Support to Others (Classify)
- (5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
	80,573	930	80,573		2
	61,611	930	61,611		3
	180,947	930	180,947		4
	338,048	930	338,048		5
41,666		930	41,666		6
37,056		930	37,056		7
					8
					9
					10
	101,980	930	101,980		11
	15,000	930	15,000		12
	50,000	930	50,000		13
	83,059	930	83,059		14
					15
					16
	165,000	930	165,000		17
353		930	353		18
45,054		930	45,054		19
	265,148	930	265,148		20
					21
	7,250	930	7,250		22
	106,438	930	106,438		23
	69,193	930	69,193		24
	4,715	930	4,715		25
223,841		930	223,841		26
	50,495	930	50,495		27
					28
	50,000	930	50,000		29
89,659		930	89,659		30
209		930	209		31
					32
					33
					34
16,068		930	16,068		35
					36
					37
13,600		930	13,600		38

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

- (2) Research Support to Edison Electric Institute
 - (3) Research Support to Nuclear Power Groups
 - (4) Research Support to Others (Classify)
 - (5) Total Cost Incurred
3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
23,165		930	23,165		2
146,008		930	146,008		3
7,868		930	7,868		4
	369,891	930	369,891		5
	145,325	930	145,325		6
109,351		930	109,351		7
					8
					9
7,714		930	7,714		10
16,303		930	16,303		11
105,153		930	105,153		12
					13
					14
					15
					16
					17
883,068	2,144,673		3,027,741		18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

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	225,114,366		
4	Transmission	54,022,868		
5	Regional Market			
6	Distribution	144,111,406		
7	Customer Accounts	118,597,676		
8	Customer Service and Informational	91,354,204		
9	Sales	2,227,853		
10	Administrative and General	305,725,215		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	941,153,588		
12	Maintenance			
13	Production	89,683,931		
14	Transmission	16,289,955		
15	Regional Market			
16	Distribution	59,723,138		
17	Administrative and General	1,921,795		
18	TOTAL Maintenance (Total of lines 13 thru 17)	167,618,819		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	314,798,297		
21	Transmission (Enter Total of lines 4 and 14)	70,312,823		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	203,834,544		
24	Customer Accounts (Transcribe from line 7)	118,597,676		
25	Customer Service and Informational (Transcribe from line 8)	91,354,204		
26	Sales (Transcribe from line 9)	2,227,853		
27	Administrative and General (Enter Total of lines 10 and 17)	307,647,010		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	1,108,772,407		1,108,772,407
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	234,193		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	15,408		
37	Customer Accounts	41,266		
38	Customer Service and Informational			
39	Sales			
40	Administrative and General	146,120		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	436,987		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply	13,972		
46	Storage, LNG Terminaling and Processing			
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	99,545		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	113,517		
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)	248,165		
55	Storage, LNG Terminating and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	114,953		
58	Customer Accounts (Line 37)	41,266		
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	146,120		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	550,504		550,504
63	Other Utility Departments			
64	Operation and Maintenance	1,185,120		1,185,120
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	1,110,508,031		1,110,508,031
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	655,413,578		655,413,578
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	655,413,578		655,413,578
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Expenditures for certain civic, political and miscellaneous	4,523,142		4,523,142
79	Nonutility Operations	7,898,496		7,898,496
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	12,421,638		12,421,638
96	TOTAL SALARIES AND WAGES	1,778,343,247		1,778,343,247

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Common Utility Plant In Service

Account	Balance Beginning of Year	Additions	Balance Retirements	End of Year
Structures and Improvements	\$1,003,706	\$-	\$ -	\$1,003,706
Office Furniture and Equipment	44,072	-	-	44,072
Transportation Equipment	-	-	-	-
Stores Equipment	11,113	-	-	11,113
Tools, Shop and Garage Equipment	49,234	-	-	49,234
Communication Equipment	11,064	-	-	11,064
Miscellaneous Equipment	-	-	-	-
Total Common Utility Plant in Service	1,119,189	-	-	\$1,119,189
Construction Work in Progress	-	-	-	-
Total Common Utility Plant	\$1,119,189	\$ -	\$ -	\$1,119,189

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Construction Work in Progress - Common Utility Plant

Description of Project	Balance End of Year
Structures and Improvements	\$558,923
Office Furniture and Equipment Acquisitions	-
Transportation Equipment	-
Stores Equipment	-
Tools, Shop and Garage Equipment	-
Communication Equipment	-
Miscellaneous Equipment	-
 Total Construction Work in Progress Common Utility Plant	 \$558,923

Departmental Allocation of Common Utility
Plant Made on Revenue Basis

Total Common Utility Plant, Page 201, line 13	\$1,119,189	Total Common CWIP	\$558,923
Electric Department	60%	671,514	Electric 60% 335,354
Gas Department	15%	167,878	Gas 15% 83,838
Water Department	25%	279,797	Water 25% 139,731
		\$1,119,189	\$558,923

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

- Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
- Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
- Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
- Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Accumulated Provision for Depreciation of Common Utility Plant

	General Plant Account 119.300	General Other Account 119.400	Total
Balance Beginning of the Year	\$ 407,381	\$ 37,776	\$ 445,157
Depreciation Provision for Year Charged to:			
Depreciation Expense	13,268	0	13,268
Other Clearing Accounts	0	4,923	4,923
Net Charges for Plant Retired:	0	0	0
Book Cost of Plant Retired	0	0	0
Cost of Removal			
Salvage	0	0	0
Net Charged for Plant Retired	0	0	0
Other Credits	0	0	0
Total Charged to Depreciation	13,268	4,923	18,191
Balance End of the Year	\$ 420,649	\$ 42,699	\$ 463,348

Departmental Allocation of Accumulated Provision
For Depreciation, Common Utility Plant

Name of Respondent Southern California Edison Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of <u>2010/Q4</u>
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COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Made on a Revenue Basis

Accumulated Provision for Depreciation, Page 201, line 14		\$	463,348
Electric Department	60%	\$	278,009
Gas Department	15%		69,502
Water Department	25%		115,837
		\$	463,348

Note: The accumulated provision for depreciation referred to above is classified as depreciation on general plant.

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Net Purchases Day Ahead Market Acct 555	178,852,524	341,050,910	389,912,434	419,555,914
8	Net Sales-Day Ahead Market Acct 555	(5,615,331)	(5,777,893)	(26,297,969)	12,273,429
9	Net Purchases-Real Time Market Acct 555	7,947,448	10,369,696	5,935,329	61,305,484
10	Net Sales-Real Time Market Acct 555	2,782,547	3,457,893	330,491	(51,255,304)
11	Access Charge	131,058	300,080	628,350	1,022,715
12	Ancillary Services	1,689,497	2,348,718	3,840,376	5,310,145
13	Cost Recovery	2,462,967	7,230,178	10,423,758	11,966,119
14	Day Ahead Energy-Congestion-Losses	(47,709,808)	(76,563,665)	(100,504,517)	(125,491,415)
15	Hour Ahead Scheduling Process-RT Stlment	12,096,691	20,187,409	32,636,472	43,308,702
16	GMC	12,168,718	23,205,306	35,294,046	54,081,119
17	FERC Fees	935,470	1,938,322	3,998,953	5,413,629
18	Other	7,587,838	9,704,429	9,855,115	10,873,978
19	Start Up	(123,292)	(123,292)	(123,292)	(123,292)
20	NERC/WECC			9,450,257	9,450,257
21					
22					
23					
24					
25					
26					
27					
28					
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42					
43					
44					
45					
46	TOTAL	173,206,327	337,328,091	375,379,803	457,691,480

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 397 Line No.: 1 Column: b

(1) Amounts in columns (b, c, d & e) are shown at 100%, but only a portion of these amounts are SCE's ISO revenues and expenses. Amounts are shown at 100% to tie out with ISO Settlement Statements.

(2) These charges are recorded to A/C 555, but are not included in line #7 & line #9.

(3) Amount based on new MRTU charge code.

(4) Amount amortize to A/C 555 over 12 months.

Schedule Page: 397 Line No.: 7 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 7 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 7 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 7 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 8 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 8 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 8 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 8 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 9 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 9 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 9 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 9 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 10 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 10 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 10 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 10 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 11 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 11 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 11 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 11 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 12 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 12 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 12 Column: d

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 12 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 13 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 13 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 13 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 13 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 14 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 14 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 14 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 14 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 15 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 15 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 15 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 15 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 16 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 16 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 16 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 16 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 17 Column: b

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 17 Column: c

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 17 Column: d

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 17 Column: e

Footnote (1)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 18 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 18 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 18 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 18 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 397 Line No.: 19 Column: b

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 19 Column: c

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 19 Column: d

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 19 Column: e

Footnote (1)(2)(3). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 20 Column: d

Footnote (3)(4). Please reference Line 1 Column b.

Schedule Page: 397 Line No.: 20 Column: e

Footnote (3)(4). Please reference Line 1 Column b.

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.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
		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		MWh			MWh	
2	Reactive Supply and Voltage		MW			MW	
3	Regulation and Frequency Response	2,223,021	MW	15,116,923	3,129,920	MW	19,646,557
4	Energy Imbalance		MWh			MWh	
5	Operating Reserve - Spinning	2,062,005	MW	13,120,297	1,332,490	MW	5,148,603
6	Operating Reserve - Supplement	764,464	MW	2,070,811	1,339,559	MW	949,325
7	Other		MW			MW	
8	Total (Lines 1 thru 7)	5,049,490		30,308,031	5,801,969		25,744,485

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 398 Line No.: 1 Column: b

"Scheduling, System Control and Dispatch" will be 0. Energy schedules will be recorded seperately in accordance to FERC Order 668.

Schedule Page: 398 Line No.: 2 Column: b

"Reactive Supply and Voltage" includes Supplemental Reactive Power at the ISO, charge codes 1302.

Schedule Page: 398 Line No.: 3 Column: b

"Regulation and Frequency Response" includes the Regulation Up and Regulation Down at the ISO, charge codes 6500, 6524, 6570, 6594, 6596, 6600, 6624, 6670, 6694, and 6696.

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

"Energy Imbalance" will be 0. Energy will be recorded seperately in accordance to FERC Order 668.

Schedule Page: 398 Line No.: 5 Column: b

"Operating Reserve - Spinning" includes Spinning Reserve at the ISO, charge codes 6100, 6124, 6170, 6194, and 6196.

Schedule Page: 398 Line No.: 6 Column: b

"Operating Reserve - Supplement" includes Non-Spinning Reserve at the ISO, charge code 6200, 6224, 6270, 6294, and 6296.

Schedule Page: 398 Line No.: 7 Column: b

"Other" includes black start energy, charge code 3101.

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: SOUTHERN CALIFORNIA EDISON COMPANY

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	14,261	20	1800	13,574			687		
2	February	13,880	9	1800	13,287			593		
3	March	13,472	17	1400	12,805			667		
4	Total for Quarter 1	41,613			39,666			1,947		
5	April	13,085	7	2000	12,384			701		
6	May	13,856	20	1400	13,107			749		
7	June	16,310	30	1600	15,263			1,047		
8	Total for Quarter 2	43,251			40,754			2,497		
9	July	21,593	16	1600	20,393			1,200		
10	August	22,064	24	1600	20,664			1,400		
11	September	22,775	27	1500	21,797			978		
12	Total for Quarter 3	66,432			62,854			3,578		
13	October	17,999	1	1500	16,648			1,351		
14	November	16,625	4	1500	15,651			974		
15	December	14,666	13	1800	13,573			1,093		
16	Total for Quarter 4	49,290			45,872			3,418		
17	Total Year to Date/Year	200,586			189,146			11,440		

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

- (1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
 (2) Report on Column (b) by month the transmission system's peak load.
 (3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
 (4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
 (5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 980 Line No.: 4 Column: b

The information will be reported by the RTO & ISO.

Schedule Page: 980 Line No.: 8 Column: b

The information will be reported by the RTO & ISO.

Schedule Page: 980 Line No.: 12 Column: b

The information will be reported by the RTO & ISO.

Schedule Page: 980 Line No.: 16 Column: b

The information will be reported by the RTO & ISO.

Name of Respondent
Southern California Edison Company

This Report Is:
(1) An Original
(2) A Resubmission

Date of Report
(Mo, Da, Yr)
04/18/2011

Year/Period of Report
End of 2010/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	53,605,682
3	Steam	10,781,565	23	Requirements Sales for Resale (See instruction 4, page 311.)	
4	Nuclear	15,699,756	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	8,618,313
5	Hydro-Conventional	4,098,914	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	299,191	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	136,979
7	Other	54,146	27	Total Energy Losses	3,666,626
8	Less Energy for Pumping	70,397	28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	66,027,600
9	Net Generation (Enter Total of lines 3 through 8)	30,863,175			
10	Purchases	35,307,844			
11	Power Exchanges:				
12	Received	176,328			
13	Delivered	356,751			
14	Net Exchanges (Line 12 minus line 13)	-180,423			
15	Transmission For Other (Wheeling)				
16	Received	10,723,992			
17	Delivered	10,686,988			
18	Net Transmission for Other (Line 16 minus line 17)	37,004			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	66,027,600			

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: SOUTHERN CALIFORNIA EDISON COMPANY

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	5,725,524	945,503	13,869	20	1900
30	February	5,103,899	729,361	13,677	9	1900
31	March	4,799,500	208,312	13,227	17	1500
32	April	4,382,571	161,415	12,875	26	1500
33	May	5,576,865	446,514	13,560	20	1500
34	June	5,809,861	315,363	15,818	30	1600
35	July	7,750,125	620,094	21,006	16	1600
36	August	7,557,252	1,286,860	21,264	24	1700
37	September	7,917,904	1,286,705	22,305	27	1600
38	October	7,393,431	1,317,065	17,213	1	1500
39	November	6,427,955	1,153,379	16,123	4	1600
40	December	-2,417,287	147,742	14,060	20	1800
41	TOTAL	66,027,600	8,618,313			

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 22 Column: b
Excludes 7,949,997 Direct Access and 21,991,741 CDWR Megawatt hours.

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 term 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: <i>Mohave</i> (b)	Plant Name: <i>Four Corners</i> (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Semi-Outdoor
3	Year Originally Constructed	1971	1969
4	Year Last Unit was Installed	1971	1970
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	916.00	785.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	1573
7	Plant Hours Connected to Load	0	8602
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1580	1500
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	16	155
12	Net Generation, Exclusive of Plant Use - KWh	-7367000	4737791000
13	Cost of Plant: Land and Land Rights	652772	0
14	Structures and Improvements	33868845	20934550
15	Equipment Costs	278381553	561480319
16	Asset Retirement Costs	0	293577
17	Total Cost	312903170	582708446
18	Cost per KW of Installed Capacity (line 17/5) Including	341.5973	742.3038
19	Production Expenses: Oper, Supv, & Engr	419161	2862954
20	Fuel	1245605	76503427
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	77317	8373939
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	9180	807174
26	Misc Steam (or Nuclear) Power Expenses	1398455	4413319
27	Rents	-64135	222870
28	Allowances	0	0
29	Maintenance Supervision and Engineering	-808	1249454
30	Maintenance of Structures	456393	579147
31	Maintenance of Boiler (or reactor) Plant	155979	14511471
32	Maintenance of Electric Plant	71046	6866142
33	Maintenance of Misc Steam (or Nuclear) Plant	118640	4021219
34	Total Production Expenses	3886833	120411116
35	Expenses per Net KWh	-0.5276	0.0254
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	COAL	GAS
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	TONS	MCF
38	Quantity (Units) of Fuel Burned	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000

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 term 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: <i>Palo Verde</i> (b)	Plant Name: <i>Other</i> (c)			
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Nuclear				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor				
3	Year Originally Constructed	1986				
4	Year Last Unit was Installed	1988				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	665.00				0.00
6	Net Peak Demand on Plant - MW (60 minutes)	661				0
7	Plant Hours Connected to Load	7927				0
8	Net Continuous Plant Capability (Megawatts)	0				0
9	When Not Limited by Condenser Water	622				0
10	When Limited by Condenser Water	0				0
11	Average Number of Employees	388				0
12	Net Generation, Exclusive of Plant Use - KWh	4929589800				0
13	Cost of Plant: Land and Land Rights	1208928				0
14	Structures and Improvements	442427257				0
15	Equipment Costs	1385530434				0
16	Asset Retirement Costs	0				0
17	Total Cost	1829166619				0
18	Cost per KW of Installed Capacity (line 17/5) Including	2750.6265				0.0000
19	Production Expenses: Oper, Supv, & Engr	10879394				0
20	Fuel	25036314				0
21	Coolants and Water (Nuclear Plants Only)	211				0
22	Steam Expenses	11076400				0
23	Steam From Other Sources	0				0
24	Steam Transferred (Cr)	0				0
25	Electric Expenses	6196446				0
26	Misc Steam (or Nuclear) Power Expenses	23850585				0
27	Rents	859045				0
28	Allowances	0				0
29	Maintenance Supervision and Engineering	5876578				0
30	Maintenance of Structures	1769399				0
31	Maintenance of Boiler (or reactor) Plant	8848657				0
32	Maintenance of Electric Plant	7911921				0
33	Maintenance of Misc Steam (or Nuclear) Plant	3508981				0
34	Total Production Expenses	105813931				0
35	Expenses per Net KWh	0.0215				0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		NUCLEAR			
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Grams of	URANIUM		
38	Quantity (Units) of Fuel Burned	0	0	760100	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	276057621	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	32.938	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	32.938	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.119	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.005	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	42566.000	0.000	0.000

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 term 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: <i>Mira Loma Sub Peaker</i> (b)	Plant Name: <i>Mountainview 3 & 4</i> (c)				
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear)	Gas Turbine	Gas Turbine				
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor	Outdoor				
3	Year Originally Constructed	2007	2005				
4	Year Last Unit was Installed	2007	2006				
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	60.50	1036.00				
6	Net Peak Demand on Plant - MW (60 minutes)	49	1052				
7	Plant Hours Connected to Load	148	8481				
8	Net Continuous Plant Capability (Megawatts)	0	0				
9	When Not Limited by Condenser Water	46	1050				
10	When Limited by Condenser Water	0	0				
11	Average Number of Employees	9	58				
12	Net Generation, Exclusive of Plant Use - KWh	4772868	6051141075				
13	Cost of Plant: Land and Land Rights	0	3200000				
14	Structures and Improvements	198805	45361141				
15	Equipment Costs	61976274	606575043				
16	Asset Retirement Costs	0	0				
17	Total Cost	62175079	655136184				
18	Cost per KW of Installed Capacity (line 17/5) Including	1027.6873	632.3708				
19	Production Expenses: Oper, Supv, & Engr	441570	2517789				
20	Fuel	272841	194494356				
21	Coolants and Water (Nuclear Plants Only)	0	0				
22	Steam Expenses	0	0				
23	Steam From Other Sources	0	0				
24	Steam Transferred (Cr)	0	0				
25	Electric Expenses	0	0				
26	Misc Steam (or Nuclear) Power Expenses	662119	5436645				
27	Rents	-155953	0				
28	Allowances	0	952252				
29	Maintenance Supervision and Engineering	333515	746480				
30	Maintenance of Structures	4524	2829458				
31	Maintenance of Boiler (or reactor) Plant	0	0				
32	Maintenance of Electric Plant	597948	17871918				
33	Maintenance of Misc Steam (or Nuclear) Plant	216041	1216068				
34	Total Production Expenses	2372605	226064966				
35	Expenses per Net KWh	0.4971	0.0374				
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	0	GAS	0	GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	0	MCF	0	MCF		
38	Quantity (Units) of Fuel Burned	0	56584	0	42620745	0	
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1030	0	1014	0	
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	4.822	0.000	0.000	4.563	0.000
41	Average Cost of Fuel per Unit Burned	0.000	4.822	0.000	0.000	4.563	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	4.683	0.000	0.000	4.499	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.057	0.000	0.000	0.032	0.000
44	Average BTU per KWh Net Generation	0.000	12207.000	0.000	0.000	7144.000	0.000

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: Barre Sub-Peaker (d)		Plant Name: Center Sub-Peaker (e)		Plant Name: Grapeland Peaker (f)		Line No.		
Gas Turbine								
Outdoor								
2007								
2007								
60.50								
49								
174								
0								
47								
0								
9								
6445554								
0								
2568501								
70353079								
0								
72921580								
1205.3154								
519934								
349632								
0								
0								
0								
0								
0								
820692								
-113532								
0								
283489								
4956								
0								
430328								
61581								
2357080								
0.3657								
GAS		GAS		0		GAS		
MCF		MCF		0		MCF		
0	72975	0	0	67254	0	0	53349	0
0	1026	0	0	1024	0	0	1029	0
0.000	4.791	0.000	0.000	4.766	0.000	0.000	4.663	0.000
0.000	4.791	0.000	0.000	4.766	0.000	0.000	4.663	0.000
0.000	4.670	0.000	0.000	4.655	0.000	0.000	4.530	0.000
0.000	0.054	0.000	0.000	0.056	0.000	0.000	0.056	0.000
0.000	11615.000	0.000	0.000	12089.000	0.000	0.000	12455.000	0.000

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
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35
			36
			37
0	0	0	38
0	0	0	39
0.000	0.000	0.000	40
0.000	0.000	0.000	41
0.000	0.000	0.000	42
0.000	0.000	0.000	43
0.000	0.000	0.000	44

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 402 Line No.: -1 Column: b

Data is reported on an SCE-Share basis, except for line 6 "Net Peak Demand on Plant" which is based on the full capability of the plant.

Schedule Page: 402 Line No.: -1 Column: c

Data is reported on an SCE-Share basis, except for line 6 "Net Peak Demand on Plant" which is based on the full capability of the plant.

Schedule Page: 402 Line No.: -1 Column: e

The data reported is on an SCE-share basis, which is consistent with nuclear industry practice.

Schedule Page: 402 Line No.: -1 Column: f

The data reported is on an SCE-share basis, which is consistent with nuclear industry practice.

Schedule Page: 402 Line No.: 5 Column: f

San Onofre Unit 2&3:

Data reported for total installed Capacity reported SCE-share basis. SCE was a 75.05% owner of SONGS 2 and 3 until December 29, 2006 and then became a 78.21% owner of SONGS 2 and 3 due to the transfer of Anaheim's share of the plants to SCE (i.e. this number reflects 3 days of SCE ownership at the 78.21% level).

Schedule Page: 402 Line No.: 6 Column: f

San Onofre Unit 2&3: Data reported for Net Peak Demand reported SCE-share basis. SCE is a 78.21% owner of SONGS 2 & 3.

Schedule Page: 402 Line No.: 7 Column: f

San Onofre Unit 2&3: Data reported for Total Plant Hours Connected to Load reported 100% basis.

Schedule Page: 402 Line No.: 9 Column: f

San Onofre Unit 2&3:

Data reported for total Net Continuous Plant Capability reported SCE-share basis. SCE was a 75.05% owner of SONGS 2 and 3 until December 29, 2006 and then became a 78.21% owner of SONGS 2 and 3 due to the transfer of Anaheim's share of the plants to SCE (i.e. this number reflects 3 days of SCE ownership at the 78.21% level).

Schedule Page: 402 Line No.: 10 Column: b

Not applicable.

Schedule Page: 402 Line No.: 10 Column: c

Not applicable.

Schedule Page: 402 Line No.: 10 Column: f

Not applicable.

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

San Onofre Unit 1: Not applicable.

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

Average Number of Employees is reported at 100% level.

Schedule Page: 402 Line No.: 12 Column: b

Mohave: Represents station usage only. Plant is standstill status effective January 1, 2006

Schedule Page: 402 Line No.: 12 Column: f

San Onofre Unit 2&3: Data reported for Net Generation, exclusive of Plant Use KWh - reported SCE-share basis. SCE is a 78.21% owner of SONGS 2 & 3.

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

The data reported is on an SCE-share basis, which is consistent with nuclear industry practice.

Schedule Page: 402.1 Line No.: -1 Column: d

Barre: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run consistently and is only on-line during peak summer hours as the need requires. Projected Annual Kw usage is 10% of total capacity during operation requirements.

Schedule Page: 402.1 Line No.: -1 Column: e

Center Sub-Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run consistently and is only on-line during peak summer hours as the need requires. Projected Annual Kw usage is 10% of total capacity during operation requirements.

Schedule Page: 402.1 Line No.: -1 Column: f

Grapeland Sub Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run consistently and is only on-line during peak summer hours as the need requires. Projected

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Annual Kw usage is 10% of total capacity during operation requirements.

Schedule Page: 402.1 Line No.: 5 Column: b

Palo Verde: Data reported for Installed Capacity reported SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

Schedule Page: 402.1 Line No.: 5 Column: d

Barre: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.1 Line No.: 5 Column: e

Center Sub-Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.1 Line No.: 5 Column: f

Grapeland Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.1 Line No.: 6 Column: b

Palo Verde: Data reported for Net Peak Demand reported SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

Schedule Page: 402.1 Line No.: 7 Column: b

Palo Verde: Data reported for Total Plant Hours Connected to Load reported 100% basis.

Schedule Page: 402.1 Line No.: 9 Column: b

Data reported for total When Not Limited by Condenser Water reported SCE share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

Schedule Page: 402.1 Line No.: 11 Column: b

Average Number of Employees is reported at 100% level.

Schedule Page: 402.1 Line No.: 12 Column: b

Palo Verde: Data reported for total Net Generation, Exclusive of Plant Use KWh- reported SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

Schedule Page: 402.1 Line No.: 26 Column: d

Barre Sub-Peaker: Reported data includes Generation Cost: \$372,436.

Schedule Page: 402.1 Line No.: 26 Column: e

Center Sub-Peaker: Reported data includes Generation Cost: \$367,400.

Schedule Page: 402.1 Line No.: 26 Column: f

Grapeland Peaker: Reported data includes Generation Cost: \$320,017.

Schedule Page: 402.2 Line No.: -1 Column: b

Mira Loma Sub Peaker: The unit has a total operating capacity in excess of 10,000 Kw per unit (Name Plate Rating). However, the unit does not run consistently and is only on-line during peak summer hours as the need requires. Projected Annual Kw usage is 10% of total capacity during operation requirements.

Schedule Page: 402.2 Line No.: 5 Column: b

Mira Loma Sub Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited by the gas turbine.

Schedule Page: 402.2 Line No.: 10 Column: b

Not applicable.

Schedule Page: 402.2 Line No.: 10 Column: c

Mountainview 3 & 4: Not applicable.

Schedule Page: 402.2 Line No.: 26 Column: b

Mira Loma: Reported Data includes Generation Cost: \$351,610.

Schedule Page: 402.2 Line No.: 26 Column: c

Mountainview 3 & 4: Reported data includes Generation Cost: \$3,309,875.

Schedule Page: 402 Line No.: 43 Column: b2

Mohave: Plant is standstill status effective January 1, 2006.

Schedule Page: 402 Line No.: 43 Column: c2

Four Corners: Composite rates are for total fuel consumed.

Schedule Page: 402 Line No.: 44 Column: b2

Mohave: Plant is standstill status effective January 1, 2006.

Schedule Page: 402 Line No.: 44 Column: c2

Four Corners: Composite rates are for total fuel consumed.

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2175 Plant Name: Big Creek No. 1 (b)	FERC Licensed Project No. 2175 Plant Name: Big Creek No. 2 (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1913	1913
4	Year Last Unit was Installed	1925	1925
5	Total installed cap (Gen name plate Rating in MW)	88.40	66.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	90	71
7	Plant Hours Connect to Load	8,744	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	83	67
10	(b) Under the Most Adverse Oper Conditions	83	67
11	Average Number of Employees	44	0
12	Net Generation, Exclusive of Plant Use - Kwh	382,375,112	360,339,285
13	Cost of Plant		
14	Land and Land Rights	0	1,344
15	Structures and Improvements	25,941,306	2,359,322
16	Reservoirs, Dams, and Waterways	4,616,197	5,389,503
17	Equipment Costs	34,077,922	24,247,418
18	Roads, Railroads, and Bridges	1,011,627	541,102
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	65,647,052	32,538,689
21	Cost per KW of Installed Capacity (line 20 / 5)	742.6137	489.3036
22	Production Expenses		
23	Operation Supervision and Engineering	520,025	381,598
24	Water for Power	359,947	311,942
25	Hydraulic Expenses	178,659	167,835
26	Electric Expenses	450,096	175,650
27	Misc Hydraulic Power Generation Expenses	1,793,169	851,338
28	Rents	217,946	183,991
29	Maintenance Supervision and Engineering	171,131	161,268
30	Maintenance of Structures	538,482	71,327
31	Maintenance of Reservoirs, Dams, and Waterways	343,863	159,612
32	Maintenance of Electric Plant	667,043	208,176
33	Maintenance of Misc Hydraulic Plant	546,176	263,901
34	Total Production Expenses (total 23 thru 33)	5,786,537	2,936,638
35	Expenses per net KWh	0.0151	0.0081

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 67 Plant Name: Big Creek No. 8 (b)	FERC Licensed Project No. 2174 Plant Name: Portal Power Plant (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1921	1956
4	Year Last Unit was Installed	1929	1956
5	Total installed cap (Gen name plate Rating in MW)	75.00	10.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	69	10
7	Plant Hours Connect to Load	7,982	8,749
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	65	11
10	(b) Under the Most Adverse Oper Conditions	65	11
11	Average Number of Employees	46	0
12	Net Generation, Exclusive of Plant Use - Kwh	260,725,820	23,701,311
13	Cost of Plant		
14	Land and Land Rights	0	34,761
15	Structures and Improvements	4,082,890	1,450,084
16	Reservoirs, Dams, and Waterways	3,285,707	3,179,061
17	Equipment Costs	16,529,575	4,282,952
18	Roads, Railroads, and Bridges	566,199	176,448
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	24,464,371	9,123,306
21	Cost per KW of Installed Capacity (line 20 / 5)	326.1916	844.7506
22	Production Expenses		
23	Operation Supervision and Engineering	293,109	77,317
24	Water for Power	268,012	24,968
25	Hydraulic Expenses	121,511	27,447
26	Electric Expenses	211,874	85,818
27	Misc Hydraulic Power Generation Expenses	684,732	104,430
28	Rents	118,466	22,111
29	Maintenance Supervision and Engineering	116,687	10,607
30	Maintenance of Structures	66,458	16,986
31	Maintenance of Reservoirs, Dams, and Waterways	95,472	69,678
32	Maintenance of Electric Plant	438,168	61,916
33	Maintenance of Misc Hydraulic Plant	202,839	47,275
34	Total Production Expenses (total 23 thru 33)	2,617,328	548,553
35	Expenses per net KWh	0.0100	0.0231

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1388 Plant Name: Poole Plant (b)	FERC Licensed Project No. 382 Plant Name: Borel (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1924	1904
4	Year Last Unit was Installed	1924	1932
5	Total installed cap (Gen name plate Rating in MW)	11.30	12.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	11	10
7	Plant Hours Connect to Load	8,685	8,084
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	11	11
10	(b) Under the Most Adverse Oper Conditions	11	11
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	32,334,280	44,042,750
13	Cost of Plant		
14	Land and Land Rights	75,235	112,464
15	Structures and Improvements	304,975	578,842
16	Reservoirs, Dams, and Waterways	405,831	12,043,725
17	Equipment Costs	2,754,060	2,904,337
18	Roads, Railroads, and Bridges	0	25,609
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	3,540,101	15,664,977
21	Cost per KW of Installed Capacity (line 20 / 5)	313.2833	1,305.4148
22	Production Expenses		
23	Operation Supervision and Engineering	192,980	210,818
24	Water for Power	25,334	101,882
25	Hydraulic Expenses	56,287	82,121
26	Electric Expenses	54,510	52,643
27	Misc Hydraulic Power Generation Expenses	443,245	504,567
28	Rents	108,284	47,174
29	Maintenance Supervision and Engineering	50,891	39,329
30	Maintenance of Structures	1,427	13,401
31	Maintenance of Reservoirs, Dams, and Waterways	47,354	212,672
32	Maintenance of Electric Plant	30,120	29,732
33	Maintenance of Misc Hydraulic Plant	11,592	13,804
34	Total Production Expenses (total 23 thru 33)	1,022,024	1,308,143
35	Expenses per net KWh	0.0316	0.0297

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Big Crk Wtr Coll Fac (b)	FERC Licensed Project No. 0 Plant Name: All Facilities (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed	0	
4	Year Last Unit was Installed	0	
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	3,544,144	0
15	Structures and Improvements	5,803,125	0
16	Reservoirs, Dams, and Waterways	92,111,762	0
17	Equipment Costs	433,395	0
18	Roads, Railroads, and Bridges	479,129	0
19	Asset Retirement Costs	0	387,910
20	TOTAL cost (Total of 14 thru 19)	102,371,555	387,910
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 67 Plant Name: Big Creek No. 2A (d)	FERC Licensed Project No. 120 Plant Name: Big Creek No. 3 (e)	FERC Licensed Project No. 2017 Plant Name: Big Creek No. 4 (f)	Line No.
Storage	Storage	Storage	1
Conventional	Conventional	Conventional	2
1928	1923	1951	3
1928	1980	1951	4
110.00	174.50	100.00	5
98	153	102	6
8,760	8,760	8,483	7
			8
99	182	100	9
99	182	100	10
0	46	0	11
523,882,452	841,968,214	487,277,996	12
			13
0	6,142	104,451	14
2,597,980	7,416,808	2,187,194	15
4,664,338	20,160,717	15,428,346	16
16,406,871	35,600,409	14,248,373	17
13,269	1,470,368	82,645	18
0	0	0	19
23,682,458	64,654,444	32,051,009	20
215.2951	370.5126	320.5101	21
			22
523,679	870,270	588,526	23
505,847	742,115	426,343	24
241,770	394,290	267,210	25
197,064	377,851	208,689	26
1,158,498	2,133,491	1,079,836	27
220,444	175,964	225,709	28
234,462	376,819	218,079	29
37,494	816,219	16,629	30
210,357	343,432	296,974	31
131,540	532,470	210,466	32
156,098	591,923	140,981	33
3,617,253	7,354,844	3,679,442	34
0.0069	0.0087	0.0076	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1388 Plant Name: Poole Res Fac (d)	FERC Licensed Project No. 1389 Plant Name: Rush Crk Res Fac (e)	FERC Licensed Project No. 1394 Plant Name: Bishop Plt Res Fac (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
7,744	0	140,925	14
254,384	56,688	105,285	15
2,085,558	5,723,630	6,930,222	16
2,079,837	18,267	7,284,773	17
0	268,727	194,511	18
0	0	0	19
4,427,523	6,067,312	14,655,716	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 406 Line No.: 11 Column: c

Operated by remote control from Big Creek No. 3.

Schedule Page: 406 Line No.: 11 Column: d

Operated by remote control from Big Creek No. 3.

Schedule Page: 406 Line No.: 11 Column: f

Operated by remote control from Big Creek No. 3.

Schedule Page: 406.1 Line No.: 11 Column: c

Operated by remote control from Big Creek No. 3.

Schedule Page: 406.1 Line No.: 11 Column: f

Operated by remote control from Big Creek No. 3.

Schedule Page: 406.2 Line No.: 1 Column: d

Operate by remote control from Poole Plant. Includes Saddlebags, Tioga, Rhinedollar. Expenses incurred at Poole and Rush Creek Reservoir Facilities are allocated to Poole and Rush Creek Plants.

These locations contain both Federal Project and Non-Project costs.

Schedule Page: 406.2 Line No.: 1 Column: e

Includes Rush Meadows Reservoir, Gem Lake and Agnew Lake.

Expenses incurred at Poole and Rush Creek Reservoir Facilities are allocated to Poole and Rush Creek Plants.

These allocations contain both Federal Project and Non-Project costs.

Schedule Page: 406.2 Line No.: 1 Column: f

Includes Equalizing Reservoir, South Lake, Sabrina Lake, Birch and McGee Creeks Diversion and miscellaneous Bishop Creek water rights.

Expenses incurred at Bishop Plant Reservoir Facilities are prorated at the end of the year to the Bishop Creek Plants.

These locations contain both Federal Project and Non-Project costs.

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
		67 Eastwood
1	Type of Plant Construction (Conventional or Outdoor)	Conventional
2	Year Originally Constructed	1987
3	Year Last Unit was Installed	1987
4	Total installed cap (Gen name plate Rating in MW)	200
5	Net Peak Demand on Plant-Megawatts (60 minutes)	210
6	Plant Hours Connect to Load While Generating	8,688
7	Net Plant Capability (in megawatts)	207
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	299,191,235
10	Energy Used for Pumping	70,397,278
11	Net Output for Load (line 9 - line 10) - Kwh	228,793,957
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	49,578,249
15	Reservoirs, Dams, and Waterways	159,999,905
16	Water Wheels, Turbines, and Generators	31,694,552
17	Accessory Electric Equipment	15,719,162
18	Miscellaneous Powerplant Equipment	5,981,246
19	Roads, Railroads, and Bridges	2,687,590
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	265,660,704
22	Cost per KW of installed cap (line 21 / 4)	1,328.3035
23	Production Expenses	
24	Operation Supervision and Engineering	277,180
25	Water for Power	374,936
26	Pumped Storage Expenses	111,811
27	Electric Expenses	191,984
28	Misc Pumped Storage Power generation Expenses	661,002
29	Rents	107,003
30	Maintenance Supervision and Engineering	102,396
31	Maintenance of Structures	15,048
32	Maintenance of Reservoirs, Dams, and Waterways	97,512
33	Maintenance of Electric Plant	272,995
34	Maintenance of Misc Pumped Storage Plant	338,143
35	Production Exp Before Pumping Exp (24 thru 34)	2,550,010
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	2,550,010
38	Expenses per KWh (line 37 / 9)	0.0085

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.

7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	0	FERC Licensed Project No. Plant Name: (d)	0	FERC Licensed Project No. Plant Name: (e)	0	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 408 Line No.: 1 Column: b

Entire Plant is underground in a cavern.

Schedule Page: 408 Line No.: 3 Column: b

Generation Equipment installed in 1987; Pumpback Equipment installed in 1990.

Schedule Page: 408 Line No.: 8 Column: b

Operated by remote control from Big Creek No. 3 Hydroelectric Generating Plant.

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	Other Production					
2	Santa Catalina Island					
3	Unit 7 Diesel	1958	1.00			
4	Unit 8 Diesel	1963	1.50			
5	Unit 10 Diesel	1966	1.10			
6	Unit 12 Diesel	1976	1.60			
7	Unit 14 Diesel	1986	1.40			
8	Unit 15 Diesel	1995	2.80			
9	TOTAL		9.40	5.0	28,585,506	38,722,201
10						
11						
12						
13	Hydro					
14	Kaweah No.1	1929	2.30	2.0	7,903,091	5,238,392
15	Kaweah No.2	1929	1.80	2.0	12,555,316	3,256,680
16	Kaweah No.3	1913	4.80	5.0	27,855,268	4,637,433
17						
18	Santa Ana No.1	1899	3.20	3.0	6,860,574	3,566,791
19	Santa Ana No.3	1999	3.10	3.0	4,985,391	21,449,290
20	Lower Tule	1909	2.50	3.0	-139,555	15,634,764
21	Mill Creek No.1	1893	0.80	1.0	973,287	719,429
22	Mill Creek No.2 & 3	1903	3.30	3.0	10,960,452	1,775,094
23	Lytle Creek	1904	0.50	1.0	3,205,700	2,178,900
24	Fontana	1917	3.00	2.0	7,793,259	630,023
25	Sierra	1922	0.50	1.0	3,812,852	763,000
26	Ontario No.1	1902	0.60	1.0	3,402,495	1,361,855
27	Ontario No.2	1963	0.30		1,854,114	391,058
28	Mammoth Pool					
29	(Fish Water Unit)	1960	0.90			
30	Big Creek No.4 (Dam 7)	1951	0.40			
31	Bishop Creek No. 2	1908	7.30	8.0	35,104,782	10,634,298
32	Bishop Creek No. 3	1913	7.80	8.0	33,056,873	5,946,034
33	Bishop Creek No. 4	1905	8.00	8.0	50,196,536	5,805,052
34	Bishop Creek No. 5	1919	4.50	4.0	15,495,688	3,889,977
35	Bishop Creek No. 6	1913	1.60	2.0	3,665,654	4,580,959
36	Rush Creek	1916	13.00	12.0	54,053,879	10,136,717
37	San Gorgonio No. 1 & 2	1923	2.40	2.0		7,102,314
38	Lundy	1911	3.00	3.0	9,190,237	5,011,940
39						
40						
41	Manufactured Gas Plant Remediation Project					
42	Proj Dvlpmnt Div Solar Photovoltaic Project:					
43	Fontana	2008	2.00	2.0	2,815,623	12,221,086
44	Chino	2009	1.00	1.0	1,421,119	6,351,619
45						
46						

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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
						2
				Diesel		3
				Diesel		4
				Diesel		5
				Diesel		6
				Diesel		7
				Diesel		8
4,119,383	3,172,406	6,334,411	2,027,325		2,078	9
						10
						11
						12
						13
2,277,562	282,402		378,507			14
1,809,267	391,980		199,336			15
966,132	818,996		278,873			16
						17
1,114,622	268,500		126,919			18
6,919,126	228,278		132,760			19
6,253,906	63,213		140,997			20
899,286	75,702		34,221			21
537,907	436,188		129,715			22
4,357,800	174,427		84,826			23
210,008	308,733		110,236			24
1,526,000	162,772		81,405			25
2,269,758	136,603		104,802			26
1,303,527	98,237		26,620			27
						28
						29
						30
1,456,753	813,041		237,865			31
762,312	810,294		217,017			32
725,632	1,346,069		266,901			33
864,439	423,719		142,868			34
2,863,099	129,129		73,844			35
779,747	1,434,100		241,817			36
2,959,298	58,662		29,191			37
1,670,647	309,986		107,753			38
						39
						40
	9,971,053					41
						42
6,660,543	148,577					43
6,901,619	74,289					44
						45
						46

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 410 Line No.: 18 Column: a

Licensed Projects:
Santa Ana #1 Project No. 1933

Schedule Page: 410 Line No.: 19 Column: a

Licensed Projects:
Santa Ana #3 Project No. 1933

Schedule Page: 410 Line No.: 20 Column: a

Licensed Projects:
Lower Tule Project No. 372

Schedule Page: 410 Line No.: 22 Column: a

Licensed Projects:
Mill Creek # 2 & 3 Project No. 1934

Schedule Page: 410 Line No.: 23 Column: a

Licensed Projects:
Lytle Creek Project No. 1932

Schedule Page: 410 Line No.: 28 Column: a

Licensed Projects:
Mammoth Pool Project No. 2085

Schedule Page: 410 Line No.: 30 Column: a

Licensed Project:
Big Creek # 4 Project No. 2017

Schedule Page: 410 Line No.: 31 Column: a

Licensed Project:
Bishop Creek # 2 Project No. 1394

Schedule Page: 410 Line No.: 32 Column: a

Licensed Project:
Bishop Creek # 3 Project No. 1394

Schedule Page: 410 Line No.: 33 Column: a

Licensed Project:
Bishop Creek # 4 Project No. 1394

Schedule Page: 410 Line No.: 34 Column: a

Licensed Project:
Bishop Creek # 5 Project No. 1394

Schedule Page: 410 Line No.: 36 Column: a

Licensed Project:
Rush Creek Project No. 1389

Schedule Page: 410 Line No.: 37 Column: a

Licensed Project:
San Geronio # 1 & 2 Project No. 344

Schedule Page: 410 Line No.: 38 Column: a

Licensed Project:
Lundy Project No. 1390

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	800 KV Lines							
2								
3	Sylmar	Celilo (CA)	1,000.00	800.00	Steel Tower	168.09		2
4	Sylmar	Celilo (NV)	1,000.00	800.00	Steel Tower	144.86		1
5								
6	500 KV Lines							
7								
8	Midway	Vincent #1 & #2	500.00	500.00	Steel Tower	225.49		2
9	Lugo	Vincent #1 & #2	500.00	500.00	Steel Tower	94.39		2
10	Lugo	Mohave (NV)	500.00	500.00	Steel Tower	9.85		1
11	El Dorado	Lugo (CA)	500.00	500.00	Steel Tower	150.67		1
12	El Dorado	Lugo (NV)	500.00	500.00	Steel Tower	26.51		1
13	Lugo	Mira Loma #2-3	500.00	500.00	Steel Tower	83.09	13.41	3
14	Lugo	Mohave (CA)	500.00	500.00	Steel Tower	165.96		1
15	El Dorado	Mohave (NV)	500.00	500.00	Steel Tower	19.93		1
16	El Dorado	Border (NV)	500.00	500.00	Steel Tower	29.65		1
17	Mira Loma	Serrano	500.00	500.00	Steel Tower	26.98	1.77	2
18	Lugo	Victorville	500.00	500.00	Steel Tower	7.57		1
19	Midway	Vincent #3	500.00	500.00	Steel Tower	52.62		1
20	Devers	Palo Verde (CA)	500.00	500.00	Steel Tower	126.45		1
21	Devers	Palo Verde (AZ)	500.00	500.00	Steel Tower	112.05		1
22	Devers	Valley	500.00	500.00	Steel Tower	41.60		1
23	Serrano	Valley	500.00	500.00	Steel Tower	40.52		1
24								
25	220 KV Lines							
26								
27	Pardee	Sylmar #1 & #2	220.00	220.00	Steel Tower	6.53	6.47	2
28	Eagle Rock	Sylmar	220.00	220.00	Steel Tower	0.04	1.75	1
29	Pardee	Vincent	220.00	220.00	Steel Tower	7.35		2
30	Santa Clara	Vincent	220.00	220.00	Steel Tower	2.74		1
31	Rio Hondo	Vincent #2	220.00	220.00	Steel Tower	4.65		1
32	Pardee	Various	220.00	220.00	Steel Tower	319.41	34.87	20
33	Cogen/Renew. Energy		220.00	220.00	Steel Tower	3.57	4.85	6
34	Devers	Various	220.00	220.00	Steel Tower	127.00	16.69	10
35	Antelope	Various	220.00	220.00	Steel Tower	255.30	15.49	10
36					TOTAL	9,921.74	2,356.41	1,146

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Chino	Various	220.00	220.00	Steel Tower	85.39	83.81	5
2	Coachella Valley	Devers	220.00	220.00	Steel Tower	0.10	0.28	1
3	Big Creek #3	Big Creek #4	220.00	220.00	Steel Tower	5.79		1
4	Big Creek #3	Springville	220.00	220.00	Steel Tower	128.32		2
5	Laguna Bell	Various	220.00	220.00	Steel Tower	89.57	39.98	13
6	Hinson	Various	220.00	220.00	Steel Tower	15.30	11.77	4
7	El Nido	Various	220.00	220.00	Steel Tower	57.52	33.89	13
8	Pisgah #2	Various	220.00	220.00	Steel Tower	305.18		5
9	Mira Loma	Various	220.00	220.00	Steel Tower	89.75	66.00	16
10	Center	Various	220.00	220.00	Steel Tower	83.57	54.08	9
11	Alamitos	Various	220.00	220.00	Steel Tower	84.63	40.04	14
12	Big Creek #4	Magunden	220.00	220.00	Steel Tower	135.41		2
13	Moorpark	Various	220.00	220.00	Steel Tower	221.67	193.08	15
14	Cima	Pisgah (NV)	220.00	220.00	Steel Tower	84.46	0.63	4
15	Kramer	Various	220.00	220.00	Steel Tower	153.63	101.99	6
16	El Dorado	Meade (NV)	220.00	220.00	Steel Tower	16.76		2
17	Santa Clara	Vincent	220.00	220.00	Steel Tower	27.48		1
18	Pearblossom	Vincent	220.00	220.00	Wood-H Frame	13.13		1
19	Ellis	Santiago #1 & #2	220.00	220.00	Steel Tower	14.93	14.56	3
20	Rio Hondo	Vincent	220.00	220.00	Steel Tower	20.35		1
21	Big Creek #2	Big Creek #8	220.00	220.00	Steel Tower	9.03		2
22	Big Creek #3	Mammoth Pool	220.00	220.00	Steel Tower	6.50		1
23	Big Creek	Various	220.00	220.00	Steel Tower	290.35	7.27	9
24	Serrano	Villa Park #1-3	220.00	220.00	Steel Tower	3.39	3.11	2
25	Big Creek #1	Eastwood	220.00	220.00	Steel Tower	4.66		1
26	Caldwell	Victor	220.00	220.00	Steel Tower	7.61		1
27	Chino	Chino	220.00	220.00	Steel Tower			
28	Devers	Various	220.00	220.00	Steel Tower	80.58	39.72	3
29								
30								
31	161 KV Lines							
32								
33	Blythe - Eagle Mountain		161.00	161.00	Wood H Frame	52.35	0.10	1
34								
35	115 KV Lines							
36					TOTAL	9,921.74	2,356.41	1,146

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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1			115.00	115.00	Steel Pole	100.66	59.60	
2			115.00	115.00	Steel Tower	419.60	158.05	
3			115.00	115.00	Wood H Frame	405.54	10.52	
4			115.00	115.00	Wood Pole	636.99	43.01	
5			115.00	115.00	Underground	8.56	5.24	
6			66.00	115.00	Steel Pole	0.57	0.18	
7			66.00	115.00	Steel Tower	7.16	0.02	
8			66.00	115.00	Wood H Frame	0.49		
9			66.00	115.00	Wood Pole	5.25	0.09	
10			55.00	115.00	Steel Tower	1.41		
11			55.00	115.00	Wood Pole	0.47		
12		Total 115 KV Lines						114
13								
14	66 KV Lines							
15			66.00	66.00	Steel Pole	303.47	125.91	
16			66.00	66.00	Wood Pole	2,607.40	563.06	
17			66.00	66.00	Steel Tower	632.31	411.45	
18			66.00	66.00	Wood H Frame	138.28	33.48	
19			66.00	66.00	Underground	181.74	145.47	
20			66.00	66.00	Wood A Frame	0.48		
21		Total 66KV Lines						801
22								
23	55 KV Lines							
24			55.00	55.00	Steel Pole	95.78		
25			55.00	55.00	Wood Pole	0.31		
26			55.00	55.00	Wood H Frame	1.38		
27			55.00	55.00	Steel Tower			
28		Total 55 KV Lines						7
29								
30	33 KV Lines							
31			33.00	33.00	Steel Tower	9.26		
32			33.00	33.00	Underground	1.54	0.37	
33			33.00	33.00	Wood Pole	17.36	13.31	
34			33.00	33.00	Steel Pole	5.12	0.78	
35			33.00	33.00	Wood H Frame	0.33	0.26	
36					TOTAL	9,921.74	2,356.41	1,146

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.
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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 (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1		Total 33 KV Lines						9
2								
3								
4								
5	33 & 66 KV Lines							
6		Total 33 & 66 KV Lines						
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	9,921.74	2,356.41	1,146

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)

8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.

9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.

10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
	136,841	39,710,510	39,847,351					3
	668,871	13,330,575	13,999,446					4
								5
								6
								7
	3,706,358	41,924,445	45,630,803	604,750	2,415,289	923,759	3,943,798	8
	1,736,812	14,917,410	16,654,222	21,304	920,877		942,181	9
	177,040	938,088	1,115,128					10
	1,448,120	22,610,692	24,058,812	819	1,459,474		1,460,293	11
	36,677	3,812,074	3,848,751		1,733		1,733	12
	10,236,733	40,584,128	50,820,861	42,265	662,503	15,498	720,266	13
	607,445	22,745,523	23,352,968	11,030	59,393	9,696	80,119	14
	132,115	2,406,897	2,539,012	1,964	13,007	-34,602	-19,631	15
	151,231	4,468,801	4,620,032	3,362	241,525		244,887	16
	1,949,719	30,529,397	32,479,116	17,029	676,668		693,697	17
	751,549	1,917,202	2,668,751	4,201	37,646		41,847	18
	3,144,755	12,122,165	15,266,920	31,828	146,453		178,281	19
	12,999,557	51,135,213	64,134,770	12,481	58,854	255,314	326,649	20
	1,341,580	42,144,626	43,486,206	15,567	145,796	66,471	227,834	21
	15,234,409	33,658,682	48,893,091	19,658	172,861	5,168	197,687	22
	5,306,899	38,266,158	43,573,057	35,205	531,982	27,549	594,736	23
								24
								25
								26
	217,137	1,154,799	1,371,936	17,849	12,399		30,248	27
	186,657	276,517	463,174	136	21,535		21,671	28
	145,317	521,234	666,551					29
	33,955	536,006	569,961					30
	72,932	576,910	649,842					31
	2,626,035	54,542,677	57,168,712	98,433	976,394	163,715	1,238,542	32
	1,466,127	3,976,673	5,442,800	10,468	90,624		101,092	33
	1,561,731	9,384,978	10,946,709	76,036	393,873	2,415	472,324	34
	7,727,582	112,738,738	120,466,320	91,613	284,673	1,655,939	2,032,225	35
	195,337,990	1,800,845,761	1,996,183,751	5,825,371	24,042,209	6,739,776	36,607,356	36

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)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	8,522,121	32,865,333	41,387,454	19,729	372,965		392,694	1
								2
	31,372	289,443	320,815	3,043	5,987		9,030	3
	1,505,890	4,197,873	5,703,763	238,712	835,247	42,215	1,116,174	4
	3,514,758	24,557,832	28,072,590	42,965	328,544	158,020	529,529	5
	1,634,441	6,623,768	8,258,209	3,875	554,830		558,705	6
	3,608,180	22,987,842	26,596,022	63,192	481,744		544,936	7
	1,156,671	9,113,043	10,269,714	28,871	244,686		273,557	8
	5,845,146	27,104,712	32,949,858	78,379	886,330	2,671	967,380	9
	2,189,394	28,726,828	30,916,222	38,910	296,558		335,468	10
	4,303,675	13,326,683	17,630,358	37,976	356,496		394,472	11
	449,753	4,239,807	4,689,560	77,692	55,901		133,593	12
	13,195,775	47,364,055	60,559,830					13
	25,048	1,197,458	1,222,506					14
	2,333,174	20,999,948	23,333,122	196,270	2,216,737	342,806	2,755,813	15
	11,017	902,889	913,906	148	14,152	306,448	320,748	16
	4,000,374	6,009,440	10,009,814	6,031	55,849	95,029	156,909	17
	332,719	1,178,519	1,511,238	11,779	22,124		33,903	18
	12,063,552	11,245,160	23,308,712	3,919	13,309		17,228	19
	642,632	5,598,177	6,240,809					20
	9,034	300,481	309,515	10,118	5,983		16,101	21
	42,221	788,996	831,217	6,796	37,978		44,774	22
	3,630,754	15,056,372	18,687,126	163,845	911,252	2,613	1,077,710	23
	78,248	2,918,602	2,996,850	1,113	9,729		10,842	24
		6,678,804	6,678,804	3,863	1,517		5,380	25
								26
								27
	1,198,858	12,131,574	13,330,432					28
								29
								30
								31
								32
4759	38,155	2,331,823	2,369,978	8,788	36,757	58,687	104,232	33
								34
								35
	195,337,990	1,800,845,761	1,996,183,751	5,825,371	24,042,209	6,739,776	36,607,356	36

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)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
	16,341,853	148,407,507	164,749,360	465,720	904,226	50,096	1,420,042	12
								13
								14
								15
								16
								17
								18
								19
								20
	34,816,596	741,389,797	776,206,393	1,636,726	2,506,689	1,944,854	6,088,269	21
								22
								23
								24
								25
								26
								27
	10,585	661,665	672,250	263,484	458,530	32,012	754,026	28
								29
								30
								31
								32
								33
								34
								35
	195,337,990	1,800,845,761	1,996,183,751	5,825,371	24,042,209	6,739,776	36,607,356	36

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)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	1,810	720,212	722,022					1
								2
								3
								4
								5
				1,297,429	3,104,530	613,403	5,015,362	6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	195,337,990	1,800,845,761	1,996,183,751	5,825,371	24,042,209	6,739,776	36,607,356	36

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 422 Line No.: 3 Column: b

Edison's share only. Joint ownership with Los Angeles Department of Water and Power, which owns 50%. Expenses shared on ownership basis and charged to accounts 560-573.

Schedule Page: 422 Line No.: 4 Column: b

Edison's share only. Joint ownership with Los Angeles Department of Water and Power, which owns 50%. Expenses shared on ownership basis and charged to accounts 560-573.

Schedule Page: 422 Line No.: 15 Column: b

Edison's share only. Joint ownership with Los Angeles Department of Water and Power, Salt River Project, Agricultural Improvement and Power District, and Nevada Power Company, which own 30.20%, 15.10% and 21.14%, respectively. Expenses shared on ownership basis and charged to Accounts 560-573.

Schedule Page: 422.1 Line No.: 16 Column: b

Edison's share only. Joint ownership with Salt River Project Agricultural Improvement and Power District, and Nevada Power

Company, which own 18.875% and 26.425%, respectively. Expenses shared on ownership basis and charged to Accounts 560-573.

Schedule Page: 422.3 Line No.: 5 Column: f

Eastern and Northern Divisions' cost accounting merged for 33KV and 66KV lines. Mileage included in the detail for 33KV and 66KV lines.

Schedule Page: 422.3 Line No.: 5 Column: g

Eastern and Northern Divisions' cost accounting merged for 33KV and 66KV lines. Mileage included in the detail for 33KV and 66KV lines.

Schedule Page: 422.3 Line No.: 6 Column: j

Eastern and Northern Divisions' cost accounting merged for 33KV and 66KV lines. Cost of lines included in the detail for 33KV and 66KV lines.

Schedule Page: 422.3 Line No.: 6 Column: k

Eastern and Northern Divisions' cost accounting merged for 33KV and 66KV lines. Cost of lines included in the detail for 33KV and 66KV lines.

Schedule Page: 422.3 Line No.: 6 Column: l

Eastern and Northern Divisions' cost accounting merged for 33KV and 66KV lines. Cost of lines included in the detail for 33KV and 66KV lines.

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 completed 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 (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Overhead	Construction					
2							
3							
4							
5							
6							
7							
8	Underground	Construction					
9							
10	Oakgrove	Riverway	0.20	UG		1	1
11	Rector	Riverway	0.20	UG		1	1
12							
13	La Cienega	Beverly	0.28	UG		1	2
14							
15	Laguna Bell	Randolph No. 4	0.43	UG		1	2
16							
17	Saugus-Appgen	Newhall	1.21	UG		1	1
18							
19	Saugus-Appgen	Newhall No. 3	1.21	UG		1	1
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		3.53			6	8

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)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
2000	KCM	CUG	66		58,139	698,384		756,523	10
2000	KCM	CUG	66		58,139	698,384		756,523	11
									12
2000	KCM	CUG	66		320,565	1,531,030		1,851,595	13
									14
1750	KCM	SDG	66		312,963	982,293		1,295,256	15
									16
2000	KCM	CUG	66			1,531,005		1,531,005	17
									18
2000	KCM	CUG	66			1,741,792		1,741,792	19
									20
									21
									22
									23
									24
									25
									26
									27
									28
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									37
									38
									39
									40
									41
									42
									43
					749,806	7,182,888		7,932,694	44

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 424 Line No.: 10 Column: e
N/A

Schedule Page: 424 Line No.: 11 Column: e
N/A

Schedule Page: 424 Line No.: 13 Column: e
N/A

Schedule Page: 424 Line No.: 15 Column: e
N/A

Schedule Page: 424 Line No.: 17 Column: e
N/A

Schedule Page: 424 Line No.: 19 Column: e
N/A

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	ANTELOPE LANCASTER	TU	220.00	66.00	
2	ANTELOPE LANCASTER	TU	66.00	12.00	
3	BAILEY LANCASTER	TU	220.00	66.00	
4	BARRE FULLERTON	TU	220.00	66.00	
5	BARRE FULLERTON	TU	66.00	12.00	
6	BARRE FULLERTON	TU	66.00	12.00	
7	CAMINO TWENTY-NINE PALMS	TU	220.00	66.00	
8	CAMINO TWENTY-NINE PALMS	TU	66.00	16.00	
9	CENTER WHITTIER	TU	220.00	66.00	
10	CENTER WHITTIER	TU	66.00	12.00	
11	CHEVMAIN EL SEGUNDO	TU	220.00	66.00	
12	CHEVMAIN EL SEGUNDO	TU	66.00	16.00	
13	CHINO ONTARIO	TU	220.00	66.00	
14	CHINO ONTARIO	TU	66.00	12.00	
15	CIMA HI DESERT	TU	220.00	16.00	
16	DEL AMO LONG BEACH	TU	230.00	66.00	
17	DEL AMO LONG BEACH	TU	220.00	66.00	
18	DEVERS PALM SPRINGS	TA	500.00	220.00	13.80
19	DEVERS PALM SPRINGS	TA	220.00	115.00	
20	EAGLE MOUNTAIN BLYTHE	TU	220.00	161.00	
21	EAGLE MOUNTAIN BLYTHE	TU	220.00	66.00	
22	EAGLE MOUNTAIN BLYTHE	TU	66.00	12.00	
23	EAGLE ROCK MONROVIA	TU	220.00	66.00	
24	EAGLE ROCK MONROVIA	TU	220.00	66.00	
25	EL NIDO INGLEWOOD	TA	220.00	66.00	
26	EL NIDO INGLEWOOD	TA	66.00	16.00	
27	ELDORADO CLARK CO., NEVADA	TA	500.00	220.00	13.80
28	ELDORADO CLARK CO., NEVADA	TA	220.00	115.00	11.50
29	ELLIS HUNTINGTON BEACH	TA	220.00	66.00	
30	ELLIS HUNTINGTON BEACH	TA	66.00	12.00	
31	ETIWANDA ETIWANDA	TU	220.00	66.00	
32	ETIWANDA ETIWANDA	TU	66.00	12.00	
33	ETIWANDA ETIWANDA	TU	66.00	12.00	
34	GOLETA SANTA BARBARA	TU	220.00	66.00	
35	GOLETA SANTA BARBARA	TU	66.00	16.00	
36	GOULD MONROVIA	TU	220.00	66.00	
37	GOULD MONROVIA	TU	220.00	16.00	
38	GOULD MONROVIA	TU	66.00	16.00	
39	GOULD MONROVIA	TU	16.00	33.00	
40	HINSON LONG BEACH	TU	220.00	66.00	

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	JOHANNA SANTA ANA	TU	220.00	66.00	
2	JOHANNA SANTA ANA	TU	66.00	12.00	
3	KRAMER RIDGECREST	TU	220.00	115.00	
4	KRAMER RIDGECREST	TU	115.00	33.00	
5	KRAMER RIDGECREST	TU	33.00	2.00	
6	LA CIENEGA SANTA MONICA	TU	220.00	66.00	
7	LA FRESA REDONDO	TU	220.00	66.00	
8	LA FRESA REDONDO	TU	66.00	16.00	
9	LA FRESA REDONDO	TU	66.00	12.00	
10	LAGUNA BELL MONTEBELLO	TU	220.00	66.00	
11	LAGUNA BELL MONTEBELLO	TU	66.00	16.00	
12	LIGHTHIPE LONG BEACH	TA	220.00	66.00	
13	LIGHTHIPE LONG BEACH	TA	66.00	12.00	
14	LUGO HI DESERT	TA	500.00	220.00	13.80
15	MESA MONTEBELLO	TA	220.00	66.00	
16	MESA MONTEBELLO	TA	66.00	16.00	
17	MESA MONTEBELLO	TA	66.00	12.00	
18	MIRA LOMA ONTARIO	TA	500.00	220.00	13.80
19	MIRA LOMA ONTARIO	TA	220.00	66.00	
20	MIRA LOMA ONTARIO	TA	66.00	12.00	
21	MIRAGE PALM SPRINGS	TU	220.00	115.00	
22	MOORPARK THOUSAND OAKS	TA	220.00	66.00	
23	MOORPARK THOUSAND OAKS	TA	66.00	16.00	
24	OLINDA FULLERTON	TU	220.00	66.00	12.00
25	OLINDA FULLERTON	TU	66.00	12.00	
26	ORMOND BEACH OXNARD	TU	220.00	66.00	
27	PADUA FOOTHILL	TU	220.00	66.00	
28	PADUA FOOTHILL	TU	66.00	12.00	
29	RANCHO VISTA ETIWANDA	TU	500.00	220.00	13.80
30	RECTOR VISALIA	TA	220.00	66.00	
31	RECTOR VISALIA	TA	220.00	10.00	
32	RECTOR VISALIA	TA	66.00	12.00	
33	RIO HONDO MONROVIA	TU	220.00	66.00	
34	RIO HONDO MONROVIA	TU	220.00	66.00	
35	RIO HONDO MONROVIA	TU	66.00	16.00	
36	RIO HONDO MONROVIA	TU	66.00	12.00	
37	SAN BERNARDINO INLAND	TU	220.00	66.00	
38	SAN BERNARDINO INLAND	TU	66.00	12.00	
39	SANTA CLARA VENTURA	TU	220.00	66.00	
40	SANTIAGO EL TORO	TU	220.00	66.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	SANTIAGO EL TORO	TU	66.00	12.00	
2	SAUGUS SAN FERNANDO	TU	220.00	66.00	
3	SAUGUS SAN FERNANDO	TU	66.00	16.00	
4	SERRANO ORANGE	TU	500.00	220.00	13.80
5	SPRINGVILLE PORTERVILLE	TU	220.00	66.00	
6	SPRINGVILLE PORTERVILLE	TU	66.00	12.00	
7	VALLEY SAN JACINTO	TA	500.00	115.00	13.80
8	VALLEY SAN JACINTO	TA	115.00	12.00	
9	VESTAL DELANO	TU	220.00	66.00	
10	VICTOR HI DESERT	TU	220.00	115.00	
11	VICTOR HI DESERT	TU	115.00	33.00	
12	VICTOR HI DESERT	TU	115.00	12.00	
13	VIEJO LAKE FOREST	TU	220.00	66.00	
14	VIEJO LAKE FOREST	TU	66.00	12.00	
15	VILLA PARK SANTA ANA	TA	220.00	66.00	
16	VILLA PARK SANTA ANA	TA	66.00	12.00	
17	VINCENT LANCASTER	TA	500.00	220.00	13.80
18	VINCENT LANCASTER	TA	500.00	220.00	
19	VISTA INLAND	TA	220.00	115.00	
20	VISTA INLAND	TA	220.00	66.00	
21	VISTA INLAND	TA	66.00	12.00	
22	WALNUT COVINA	TA	220.00	66.00	
23	WALNUT COVINA	TA	66.00	12.00	
24	ALAMITOS LONG BEACH	TA	220.00	66.00	
25	BIG CREEK 1 BIG CREEK	TA	33.00	33.00	
26	BIG CREEK 1 BIG CREEK	TA	220.00	12.00	
27	BIG CREEK 1 BIG CREEK	TA	33.00	12.00	
28	BIG CREEK 1 BIG CREEK	TA	7.00	7.00	
29	BIG CREEK 2 NR. BIG CREEK	TU	220.00	12.00	
30	BIG CREEK 2 NR. BIG CREEK	TU	12.00	7.00	
31	BIG CREEK 2 P.H. NR. BIG CREEK	TU	220.00	7.00	
32	BIG CREEK 2A NR. BIG CREEK	TU	220.00	12.00	
33	BIG CREEK 3 NR. AUBERRY	TA	220.00	12.00	
34	BIG CREEK 3 NR. AUBERRY	TA	12.00	12.00	
35	BIG CREEK 3 NR. AUBERRY	TA	2.00	1.00	
36	BIG CREEK 4 NR. AUBERRY	TU	220.00	12.00	
37	BIG CREEK 4 NR. AUBERRY	TU	12.00	1.00	
38	BIG CREEK 8 NR. BIG CREEK	TA	220.00	12.00	
39	BIG CREEK 8 NR. BIG CREEK	TA	12.00	1.00	
40	BOREL LAKE ISABELLA	TU	66.00	2.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BUCKWIND NORTH PALM SPRINGS	TU	115.00	12.00	
2	CARBOGEN LONG BEACH	TU	66.00	12.00	
3	CHARMIN OXNARD	TU	66.00	12.00	
4	CHARMIN OXNARD	TU	66.00	4.00	
5	CHEVGEN EL SEGUNDO	TU	66.00	14.00	
6	COOL WATER DAGGETT	TU	115.00	4.00	
7	CRYCO INDUSTRY	TU	66.00	14.00	
8	DAIRYMANS TULARE	TU	66.00	12.00	
9	EASTWOOD SHAVER LAKE	TA	220.00	12.00	
10	ETIWANDA ETIWANDA	TU	220.00	66.00	
11	ETIWANDA ETIWANDA	TU	66.00	12.00	
12	ETIWANDA ETIWANDA	TU	66.00	12.00	
13	FEDERALGEN COMMERCE	TU	66.00	12.00	
14	GRAPELAND ETIWANDA	TU	66.00	66.00	
15	HILLGEN CITY OF INDUSTRY	TU	66.00	12.00	
16	HOOVER** BOULDER CANYON	TA	220.00	12.00	
17	HOOVER** S.C.E BOULDER CANYON	TA	220.00	12.00	
18	KAWEAH 1 THREE RIVERS	TU	66.00	12.00	
19	KAWEAH 2 THREE RIVERS	TU	66.00	12.00	
20	KAWEAH 3 THREE RIVERS	TU	66.00	12.00	
21	KERN RIVER 1 KERN CANYON	TU	66.00	2.00	
22	KERN RIVER 3 KERNVILLE	TA	66.00	12.00	
23	LANPRI LANCASTER	TU	66.00	12.00	
24	LUNDY NR. LEE VINING	TU	55.00	16.00	
25	LUNDY P.H. NR. LEE VINING	TU	55.00	2.00	
26	MAMMOTH BIG CREEK	TU	220.00	12.00	
27	MAMMOTH POOL (DAM) BIG CREEK	TU	12.00	2.00	
28	MCGRATH BEACH OXNARD	TU	66.00	66.00	
29	MIDWIND LANCASTER	DU	66.00	12.00	
30	MILL CREEK NO.1 INLAND	TU	12.00	1.00	
31	MILL CREEK NO.2 INLAND	TU	12.00	1.00	
32	MOHAVE LAUGHLIN, NE	TA	500.00	12.00	
33	NORTHWIND LANCASTER	DU	66.00	12.00	
34	ONTARIO PH.2 SAN ANTONIO CANYON	TU	12.00	12.00	
35	ORCOGEN HUNTINGTON BEACH	TU	66.00	12.00	
36	ORMOND BEACH OXNARD	TU	220.00	66.00	
37	PALO VERDE WEST OF BUCKEYE	TA	525.00	25.00	
38	PALO VERDE WEST OF BUCKEYE	TA	525.00	23.00	13.00
39	PALO VERDE 2 WEST OF BUCKEYE	TA	525.00	25.00	
40	PALO VERDE 2 WEST OF BUCKEYE	TA	525.00	23.00	13.00

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	PALO VERDE 3 WEST OF BUCKEYE	TA	525.00	25.00	
2	PALO VERDE 3 WEST OF BUCKEYE	TA	525.00	23.00	13.00
3	PALOGEN ROLLING HILLS	TU	66.00	12.00	
4	PEBBLY BEACH AVALON	TU	12.00	2.00	
5	PITCHGEN SAUGUS	TU	66.00	12.00	
6	PLANT 2 NR. BISHOP	TU	55.00	12.00	
7	PLANT 2 NR. BISHOP	TU	55.00	2.00	
8	PLANT 2 NR. BISHOP	TU	12.00	2.00	
9	PLANT 3 NR. BISHOP	TU	115.00	2.00	
10	PLANT 4 NR. BISHOP	TA	115.00	2.00	
11	PLANT 5 NR. BISHOP	TU	55.00	2.00	
12	PLANT 6 NR. BISHOP	TU	55.00	2.00	
13	POOLE NR. LEE VINING	TA	115.00	12.00	
14	POOLE NR. LEE VINING	TA	12.00	7.00	
15	PORTAL BIG CREEK	TU	33.00	4.00	
16	PROCGEN OXNARD	TU	66.00	12.00	
17	RENWIND PALM SPRINGS	TU	115.00	12.00	
18	REPRO EL SEGUNDO	TU	66.00	16.00	
19	RUSH CREEK NR. JUNE LAKE	TA	115.00	2.00	
20	RUSH CREEK NR. JUNE LAKE	TA	4.00	2.00	
21	SAN BERNARDINO INLAND	TU	220.00	66.00	
22	SAN BERNARDINO INLAND	TU	66.00	12.00	
23	SAN ONOFRE NR. SAN CLEMENTE	TA	220.00	12.00	
24	SANIGEN WALNUT	TU	66.00	12.00	
25	SANTA ANA RIVER 1 FOOTHILL	TU	33.00	2.00	
26	SANTA ANA RIVER 3 FOOTHILL	TU	33.00	1.00	
27	SERRFGEN LONG BEACH	TU	66.00	12.00	
28	SIGGEN NORWALK	TU	66.00	12.00	
29	SKINWATER WINCHESTER	TU	33.00	4.00	
30	SOUTHWIND LANCASTER	TU	66.00	12.00	
31	TIMBERWINE BIG CREEK	TU	33.00	12.00	
32	TULE NR. SPRINGVILLE	TU	66.00	12.00	
33	VENWIND PALM SPRINGS	TU	115.00	12.00	
34	WILLAMETTE OXNARD	TU	66.00	12.00	
35	WINDHUB TEHACAHPI	TU	500.00	220.00	
36	ACTON SAN JACINTO	DU	66.00	12.00	
37	AEROJET AZUSA	DU	66.00	12.00	
38	AFG HESPERIA	DU	115.00	12.00	
39	ALDER FOOTHILL	DU	66.00	12.00	
40	ALESSANDRO SAN JACINTO	DU	115.00	33.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ALESSANDRO SAN JACINTO	DU	115.00	12.00	
2	ALHAMBRA MONTEBELLO	DU	66.00	16.00	
3	ALHAMBRA MONTEBELLO	DU	66.00	4.00	
4	ALLEN MONROVIA	DU	16.00	4.00	
5	ALON COMPTON	DU	66.00	12.00	
6	AMADOR MONTEBELLO	DU	66.00	16.00	
7	AMADOR MONTEBELLO	DU	66.00	4.00	
8	AMALIA MONTEBELLO	DU	16.00	4.00	
9	AMARGO RIDGECREST	DU	33.00	4.00	
10	AMBOY TWENTY-NINE PALMS	DU	33.00	12.00	
11	AMCO TORRANCE	DU	66.00	12.00	
12	AMCO TORRANCE	DU	12.00	4.00	
13	AMERON ETIWANDA	DU	66.00	33.00	
14	ANAVERDE LANCASTER	DU	66.00	12.00	
15	ANITA MONROVIA	DU	66.00	16.00	
16	ANITA MONROVIA	DU	66.00	4.00	
17	APL LONG BEACH	DU	66.00	4.00	
18	APOLLO HUNTINGTON BEACH	DU	66.00	12.00	
19	APPLE VALLEY HI DESERT	DU	115.00	12.00	
20	AQUEDUCT HI DESERT	DU	115.00	12.00	
21	AQUEDUCT HI DESERT	DU	115.00	12.00	
22	ARCADIA MONROVIA	DU	66.00	16.00	
23	ARCADIA MONROVIA	DU	66.00	4.00	
24	ARCH BEACH EL TORO	DU	12.00	4.00	
25	ARCHIBALD FOOTHILL	DU	66.00	12.00	
26	ARCHLINE ONTARIO	DU	66.00	12.00	
27	ARCO LONG BEACH	DU	66.00	12.00	
28	ARROWHEAD ARROWHEAD	DU	115.00	33.00	
29	ARROWHEAD ARROWHEAD	DU	33.00	12.00	
30	ARROWHEAD ARROWHEAD	DU	33.00	4.00	
31	ARROYO MONROVIA	DU	66.00	16.00	
32	ARROYO MONROVIA	DU	16.00	4.00	
33	ARTESIA LONG BEACH	DU	12.00	4.00	
34	ASTRO LONG BEACH	DU	66.00	12.00	
35	ATHENS COMPTON	DU	16.00	4.00	
36	ATWOOD FULLERTON	DU	66.00	12.00	
37	AULD SAN JACINTO	DU	115.00	33.00	
38	AULD SAN JACINTO	DU	115.00	12.00	
39	AULD SAN JACINTO	DU	33.00	12.00	
40	AZUSA AZUSA	DU	66.00	12.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BADILLO COVINA	DU	12.00	4.00	
2	BAIN MIRA LOMA	DU	66.00	12.00	
3	BAKER HI DESERT	DU	115.00	33.00	
4	BAKER HI DESERT	DU	115.00	12.00	
5	BANDINI COMPTON	DU	66.00	16.00	
6	BANNING INLAND	DU	115.00	34.00	
7	BARSTOW HI DESERT	DU	33.00	12.00	
8	BARTOLO WHITTIER	DU	12.00	4.00	
9	BASSETT COVINA	DU	66.00	12.00	
10	BASSETT COVINA	DU	66.00	12.00	
11	BASTA FULLERTON	DU	12.00	4.00	
12	BAYSIDE HUNTINGTON BEACH	DU	66.00	12.00	
13	BAYSIDE HUNTINGTON BEACH	DU	66.00	12.00	
14	BEAUMONT INLAND	DU	12.00	4.00	
15	BEDFORD SANTA MONICA	DU	16.00	4.00	
16	BELDING PALM SPRINGS	DU	33.00	4.00	
17	BELMONT LONG BEACH	DU	12.00	4.00	
18	BELVEDERE MONTEBELLO	DU	16.00	4.00	
19	BEVERLY SANTA MONICA	DU	66.00	16.00	
20	BEVERLY SANTA MONICA	DU	66.00	4.00	
21	BICKNELL MONTEBELLO	DU	16.00	4.00	
22	BIXBY LONG BEACH	DU	12.00	4.00	
23	BLACK MOUNTAIN APPLE VALLEY	DU	115.00	4.00	
24	BLISS TULARE	DU	66.00	12.00	
25	BLOOMINGTON FOOTHILL	DU	66.00	12.00	
26	BLUFF COVE REDONDO	DU	16.00	4.00	
27	BLYTHE SCE BLYTHE	DU	33.00	12.00	
28	BLYTHE SCE BLYTHE	DU	33.00	5.00	
29	BOLSA HUNTINGTON BEACH	DU	66.00	12.00	
30	BOOST LONG BEACH	DU	66.00	12.00	
31	BORREGO EL TORO	DU	66.00	12.00	
32	BOVINE LONG BEACH	DU	66.00	12.00	
33	BOWL LONG BEACH	DU	66.00	12.00	
34	BOWL LONG BEACH	DU	66.00	4.00	
35	BOXWOOD PORTERVILLE	DU	66.00	12.00	
36	BRADBURY MONROVIA	DU	66.00	16.00	
37	BREA FULLERTON	DU	66.00	12.00	
38	BREEZE LANCASTER	DU	66.00	12.00	
39	BREW IRWINDALE	DU	66.00	4.00	
40	BREWSTER COMPTON	DU	16.00	4.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	BRIDGE REDONDO	DU	66.00	4.00	
2	BRIGHTON REDONDO	DU	66.00	16.00	
3	BRISTOL SANTA ANA	DU	12.00	4.00	
4	BROADWAY LONG BEACH	DU	66.00	12.00	
5	BROADWAY LONG BEACH	DU	12.00	4.00	
6	BROOKHURST HUNTINGTON BEACH	DU	66.00	12.00	
7	BROWNING DELANO	DU	66.00	12.00	
8	BRYAN SANTA ANA	DU	66.00	12.00	
9	BRYMAN HI DESERT	DU	33.00	4.00	
10	BULLIS COMPTON	DU	66.00	16.00	
11	BULLIS COMPTON	DU	66.00	4.00	
12	BUNKER SAN JACITO	DU	115.00	12.00	
13	BURNT MILL LAKE ARROWHEAD	DU	33.00	12.00	
14	BURRO FLATS CHATSWORTH	DU	66.00	4.00	
15	CABAZON PALM SPRINGS	DU	33.00	12.00	
16	CABRILLO EL TORO	DU	66.00	12.00	
17	CADY HI DESERT	DU	33.00	12.00	
18	CAJALCO PERRIS	DU	115.00	12.00	
19	CAL CEMENT MOJAVE	DU	66.00	4.00	
20	CALCITY CAL CITY	DU	33.00	12.00	
21	CALDEN COMPTON	DU	66.00	16.00	
22	CALECTRIC INLAND	DU	115.00	33.00	
23	CAMAR VENTURA	DU	16.00	4.00	
24	CAMARILLO VENTURA	DU	66.00	16.00	
25	CAMDEN SANTA ANA	DU	66.00	12.00	
26	CAMERON LONG BEACH	DU	66.00	12.00	
27	CANTIL RIDGECREST	DU	33.00	12.00	
28	CANYON FULLERTON	DU	66.00	12.00	
29	CANYON LAKE SAN JACINTO	DU	33.00	12.00	
30	CAPITAN SANTA BARBARA	DU	66.00	16.00	
31	CAPTIVE DELANO	DU	66.00	12.00	
32	CARBONIC CARSON	DU	66.00	12.00	
33	CARDIFF INLAND	DU	66.00	33.00	
34	CARDIFF INLAND	DU	66.00	12.00	
35	CARMENITA WHITTIER	DU	66.00	12.00	
36	CARODEAN TWENTY-NINE PALMS	DU	115.00	12.00	
37	CAROLINA FULLERTON	DU	66.00	12.00	
38	CARSON COMPTON	DU	66.00	16.00	
39	CASITAS VENTURA	DU	66.00	16.00	
40	CATHEDRAL CITY PALM SPRINGS	DU	33.00	5.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CATHEDRAL CITY PALM SPRINGS	DU	33.00	5.00	
2	CEDARWOOD HUNTINGTON BEACH	DU	12.00	4.00	
3	CERTIFIED LONG BEACH	DU	66.00	12.00	
4	CHANNEL ISLAND TEHACHAPI	DU	66.00	16.00	
5	CHASE ONTARIO	DU	66.00	12.00	
6	CHATHAM VISALIA	DU	66.00	12.00	
7	CHATSWORTH THOUSAND OAKS	DU	66.00	16.00	
8	CHERRY LONG BEACH	DU	66.00	12.00	
9	CHESTNUT SANTA ANA	DU	66.00	12.00	
10	CHEVCENTRAL EL SUGUNDO	DU	66.00	16.00	
11	CHIQUITA EL TORO	DU	66.00	12.00	
12	CITRUS COVINA	DU	66.00	12.00	
13	CLAREMONT CLAREMONT	DU	66.00	4.00	
14	CLARK LONG BEACH	DU	66.00	4.00	
15	COFFEE PALM SPRINGS	DU	33.00	12.00	
16	COLONIA VENTURA	DU	66.00	16.00	
17	COLORADO SANTA MONICA	DU	66.00	16.00	
18	COLOSSUS VALENCIA	DU	66.00	16.00	
19	COLTON FOOTHILL	DU	66.00	12.00	
20	COLTON CEMENT COLTON	DU	66.00	12.00	
21	COLUMBINE DELANO	DU	66.00	12.00	
22	COMPRESS TORRANCE	DU	66.00	12.00	
23	COMPTON COMPTON	DU	16.00	4.00	
24	CONCHO PALM SPRINGS	DU	115.00	12.00	
25	CORNERS LONG BEACH	DU	66.00	2.00	
26	CORNUTA COMPTON	DU	66.00	12.00	
27	CORONA ONTARIO	DU	66.00	33.00	
28	CORONA ONTARIO	DU	66.00	12.00	
29	CORRECTION TEHACHAPI	DU	66.00	12.00	
30	CORTEZ COVINA	DU	66.00	12.00	
31	CORUM LANCASTER	DU	66.00	12.00	
32	COSMIC HAWTHORNE	DU	66.00	12.00	
33	COSO LITTLE LAKE	DU	115.00	12.00	
34	COSTA MESA HUNTINGTON BEACH	DU	12.00	4.00	
35	COTTONWOOD HI DESERT	DU	115.00	33.00	
36	COVINA COVINA	DU	12.00	4.00	
37	CRATER THOUSAND OAKS	DU	66.00	16.00	
38	CREST REDONDO	DU	66.00	16.00	
39	CREST REDONDO	DU	66.00	16.00	
40	CRESTMORE RUBIDOUX	DU	66.00	4.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	CROWN HUNTINGTON BEACH	DU	66.00	12.00	
2	CUCAMONGA FOOTHILL	DU	66.00	12.00	
3	CUDAHY COMPTON	DU	66.00	16.00	
4	CUDAHY COMPTON	DU	66.00	4.00	
5	CULVER SANTA MONICA	DU	66.00	16.00	
6	CULVER SANTA MONICA	DU	66.00	16.00	
7	CULVER SANTA MONICA	DU	66.00	4.00	
8	CUMMINGS LANCASTER	DU	66.00	12.00	
9	CYPRESS FULLERTON	DU	66.00	12.00	
10	CYPRESS FULLERTON	DU	12.00	4.00	
11	DAGGETT BARSTOW	DU	33.00	4.00	
12	DAISY LONG BEACH	DU	12.00	4.00	
13	DALTON MONROVIA	DU	66.00	12.00	
14	DATABANK CORONA	DU	66.00	12.00	
15	DAVIDSON CITY LONG BEACH	DU	12.00	4.00	
16	DECLEZ FOOTHILL	DU	66.00	12.00	
17	DECLEZ FOOTHILL	DU	12.00	4.00	
18	DEFRAIN BLYTHE	DU	33.00	12.00	
19	DEL ROSA INLAND	DU	66.00	12.00	
20	DEL SUR LANCASTER	DU	66.00	12.00	
21	DELANO DELANO	DU	66.00	12.00	
22	DELANO DELANO	DU	66.00	4.00	
23	DESAL SANTA BARBARA	DU	66.00	12.00	
24	DESERT OUTPOST CATHEDRAL CITY	DU	33.00	12.00	
25	DIAMOND BAR COVINA	DU	66.00	12.00	
26	DIKE LONG BEACH	DU	66.00	12.00	
27	DITMAR REDONDO	DU	66.00	16.00	
28	DITMAR REDONDO	DU	16.00	4.00	
29	DIVISADERO VISALIA	DU	12.00	4.00	
30	DOHENY SANTA MONICA	DU	16.00	4.00	
31	DOMHILL CARSON	DU	66.00	4.00	
32	DOUGLAS EL SEGUNDO	DU	66.00	16.00	
33	DOUGOIL PARAMOUNT	DU	66.00	12.00	
34	DOWNEY WHITTIER	DU	12.00	4.00	
35	DOWNEY WHITTIER	DU	12.00	4.00	
36	DOWNEY MED WHITTIER	DU	66.00	12.00	
37	DOWNS RIDGECREST	DU	33.00	12.00	
38	DUARTE MONROVIA	DU	16.00	4.00	
39	DUCTILE EL MONTE	DU	66.00	16.00	
40	DUNES BLYTHE	DU	33.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	DUNN SIDING HI DESERT	DU	115.00	12.00	
2	EARLIMART DELANO	DU	66.00	12.00	
3	EAST BARSTOW HI DESERT	DU	33.00	4.00	
4	EATON MONROVIA	DU	66.00	16.00	
5	EDGEWATER HUNTINGTON BEACH	DU	12.00	4.00	
6	EDINGER SANTA ANA	DU	12.00	4.00	
7	EDWARDS RIDGECREST	DU	115.00	33.00	
8	EDWARDS RIDGECREST	DU	115.00	33.00	
9	EISENHOWER PALM SPRINGS	DU	115.00	33.00	
10	EISENHOWER PALM SPRINGS	DU	115.00	12.00	
11	EL PORTO REDONDO	DU	16.00	4.00	
12	EL SOBRANTE ONTARIO	DU	33.00	12.00	
13	EL SOBRANTE ONTARIO	DU	33.00	12.00	
14	ELCANS VISALIA	DU	66.00	12.00	
15	ELSINORE SAN JACINTO	DU	115.00	33.00	
16	ELSINORE SAN JACINTO	DU	115.00	12.00	
17	ELSINORE SAN JACINTO	DU	33.00	2.00	
18	ELY FULLERTON	DU	66.00	12.00	
19	ERIC LONG BEACH	DU	66.00	12.00	
20	ESTERO VENTURA	DU	66.00	16.00	
21	ESTRELLA EL TORO	DU	66.00	12.00	
22	EUCLID ONTARIO	DU	12.00	4.00	
23	EXETER VISALIA	DU	12.00	4.00	
24	FAIR OAKS MONROVIA	DU	16.00	4.00	
25	FAIRFAX SANTA MONICA	DU	66.00	16.00	
26	FAIRFAX SANTA MONICA	DU	16.00	4.00	
27	FAIRVIEW SANTA ANA	DU	66.00	12.00	
28	FARRELL PALM SPRINGS	DU	115.00	12.00	
29	FELTON INGLEWOOD	DU	66.00	16.00	
30	FELTON INGLEWOOD	DU	16.00	4.00	
31	FERNWOOD COMPTON	DU	66.00	16.00	
32	FIBRE RIVERSIDE	DU	66.00	4.00	
33	FILLMORE VENTURA	DU	66.00	16.00	
34	FIREHOUSE ONTARIO	DU	66.00	12.00	
35	FLANCO FOOTHILL	DU	12.00	4.00	
36	FLORADAY WHITTIER	DU	12.00	4.00	
37	FOREST HOME INLAND	DU	33.00	2.00	
38	FORGE RANCHO CUCAMONGA	DU	66.00	12.00	
39	FRANCIS ONTARIO	DU	66.00	12.00	
40	FRAZIER PARK LANCASTER	DU	66.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	FREMONT COMPTON	DU	66.00	16.00	
2	FREMONT COMPTON	DU	16.00	4.00	
3	FRIENDLY HILLS WHITTIER	DU	12.00	4.00	
4	FRIENDLY HILLS WHITTIER	DU	12.00	4.00	
5	FRUITLAND COMPTON	DU	66.00	16.00	
6	FRUITLAND COMPTON	DU	66.00	4.00	
7	FUEL LONG BEACH	DU	66.00	4.00	
8	FULLERTON FULLERTON	DU	66.00	12.00	
9	FULLERTON FULLERTON	DU	66.00	4.00	
10	GAGE COMPTON	DU	16.00	4.00	
11	GALAXY MANHATTAN BEACH	DU	66.00	12.00	
12	GALAXY MANHATTAN BEACH	DU	66.00	4.00	
13	GALE HI DESERT	DU	115.00	33.00	
14	GALLATIN WHITTIER	DU	66.00	12.00	
15	GANESHA COVINA	DU	66.00	12.00	
16	GANESHA COVINA	DU	12.00	4.00	
17	GARFIELD PASADENA	DU	66.00	4.00	
18	GARNET PALM SPRINGS	DU	115.00	33.00	
19	GARNET PALM SPRINGS	DU	33.00	12.00	
20	GARVEY MONTEBELLO	DU	16.00	4.00	
21	GATX CARSON	DU	66.00	12.00	
22	GAVILAN SAN JACINTO	DU	33.00	12.00	
23	GAVIOTA SANTA BARBARA	DU	66.00	16.00	
24	GENAMIC RANCHO CUCAMONGA	DU	66.00	12.00	
25	GETTY VENTURA	DU	66.00	16.00	
26	GILBERT FULLERTON	DU	66.00	12.00	
27	GISLER HUNTINGTON BEACH	DU	66.00	12.00	
28	GLEN AVON ONTARIO	DU	66.00	12.00	
29	GLEN IVY GLEN IVY HOT SPRINGS	DU	33.00	12.00	
30	GLENNVILLE DELANO	DU	66.00	12.00	
31	GOLDTOWN LANCASTER	DU	66.00	12.00	
32	GONZALES VENTURA	DU	66.00	16.00	
33	GORMAN LANCASTER	DU	66.00	12.00	
34	GOSHEN VISALIA	DU	66.00	12.00	
35	GRAHAM COMPTON	DU	16.00	4.00	
36	GRANADA MONTEBELLO	DU	16.00	4.00	
37	GRANGEVILLE HANFORD	DU	12.00	4.00	
38	GREAT LAKES ROSAMOND	DU	66.00	12.00	
39	GREENHORN DELANO	DU	66.00	2.00	
40	GREENING LONG BEACH	DU	66.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	GRISWOLD HUNTINGTON BEACH	DU	16.00	4.00	
2	HAAGEN TULARE	DU	66.00	4.00	
3	HAMILTON HUNTINGTON BEACH	DU	66.00	12.00	
4	HANFORD HANFORD	DU	66.00	12.00	
5	HANFORD HANFORD	DU	66.00	4.00	
6	HANJIN LONG BEACH	DU	66.00	12.00	
7	HARDING MONTEBELLO	DU	16.00	4.00	
8	HARPER LAKE HI DESERT	DU	33.00	5.00	
9	HARVARD HI DESERT	DU	33.00	12.00	
10	HASKELL SAN FERNANDO	DU	66.00	16.00	
11	HATHAWAY LONG BEACH	DU	66.00	12.00	
12	HATHAWAY LONG BEACH	DU	66.00	4.00	
13	HAVASU BLYTHE	DU	66.00	16.00	
14	HAVEDA REDONDO	DU	16.00	4.00	
15	HAVILAH KERNVILLE	DU	66.00	12.00	
16	HEDDA LONG BEACH	DU	12.00	4.00	
17	HELENDALE HI DESERT	DU	33.00	12.00	
18	HELIJET PALMDALE	DU	66.00	12.00	
19	HELIJET PALMDALE	DU	12.00	4.00	
20	HEMET SAN JACINTO	DU	33.00	12.00	
21	HEMET SAN JACINTO	DU	33.00	5.00	
22	HESPERIA HI DESERT	DU	115.00	12.00	
23	HI DESERT TWENTY-NINEPALMS	DU	115.00	33.00	
24	HI DESERT TWENTY-NINEPALMS	DU	33.00	25.00	
25	HIGHLAND INLAND	DU	66.00	12.00	
26	HINKLEY HI DESERT	DU	33.00	12.00	
27	HOLGATE BORON	DU	33.00	12.00	
28	HOLIDAY PALM SPRINGS	DU	33.00	4.00	
29	HOMART INLAND	DU	115.00	12.00	
30	HOPEFUL DUARTE	DU	66.00	12.00	
31	HOWARD INGLEWOOD	DU	66.00	4.00	
32	HOYT MONTEBELLO	DU	16.00	4.00	
33	HUGHESAIR EL SEGUNDO	DU	66.00	12.00	
34	HUGHTRON TORRANCE	DU	66.00	4.00	
35	HUNTINGTON PARK COMPTON	DU	16.00	4.00	
36	HUSTON ARROWHEAD	DU	33.00	12.00	
37	HUSTON ARROWHEAD	DU	33.00	2.00	
38	IDYLLWILD SAN JACINTO	DU	33.00	12.00	
39	IDYLLWILD SAN JACINTO	DU	33.00	2.00	
40	IMPERIAL WHITTIER	DU	66.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	IMPERIAL WHITTIER	DU	66.00	4.00	
2	INDIAN WELLS PALM SPRINGS	DU	115.00	12.00	
3	INDUSTRY COVINA	DU	66.00	12.00	
4	INDUSTRY COVINA	DU	66.00	12.00	
5	INDUSTRY COVINA	DU	66.00	4.00	
6	INGLEWOOD INGLEWOOD	DU	66.00	16.00	
7	INGLEWOOD INGLEWOOD	DU	66.00	4.00	
8	INJECTION LONG BEACH	DU	66.00	12.00	
9	INLAND ONTARIO	DU	66.00	12.00	
10	INYOKERN RIDGECREST	DU	115.00	33.00	
11	INYOKERN RIDGECREST	DU	33.00	12.00	
12	INYOKERN TOWN RIDGECREST	DU	33.00	5.00	
13	IRON MT. SCE DESERT CENTER	DU	16.00	7.00	
14	IRVINE EL TORO	DU	66.00	12.00	
15	ISABELLA KERNVILLE	DU	66.00	12.00	
16	ISLA VISTA SANTA BARBARA	DU	66.00	16.00	
17	IVAR MONTEBELLO	DU	16.00	4.00	
18	IVYGLEN ONTARIO	DU	115.00	12.00	
19	JEFFERSON ONTARIO	DU	66.00	12.00	
20	JERSEY COMPTON	DU	66.00	16.00	
21	JOSHUA TREE TWENTY-NINE PALMS	DU	33.00	12.00	
22	KEMPSTER FOOTHILL	DU	33.00	4.00	
23	KERNVILLE KERNVILLE	DU	66.00	16.00	
24	KERNVILLE KERNVILLE	DU	66.00	12.00	
25	KIMBALL CHINO	DU	66.00	12.00	
26	LA CANADA MONROVIA	DU	66.00	16.00	
27	LA CANADA MONROVIA	DU	16.00	4.00	
28	LA HABRA FULLERTON	DU	66.00	12.00	
29	LA MIRADA WHITTIER	DU	66.00	12.00	
30	LA PALMA FULLERTON	DU	66.00	12.00	
31	LA PALMA FULLERTON	DU	66.00	12.00	
32	LA VETA SANTA ANA	DU	66.00	12.00	
33	LAFAYETTE HUNTINGTON BEACH	DU	66.00	12.00	
34	LAKEWOOD LONG BEACH	DU	66.00	4.00	
35	LAMPSON SANTA ANA	DU	66.00	12.00	
36	LANCASTER LANCASTER	DU	66.00	12.00	
37	LANCASTER LANCASTER	DU	12.00	4.00	
38	LANDING BLYTHE	DU	66.00	16.00	
39	LARDER LONG BEACH	DU	12.00	4.00	
40	LARK ELLEN COVINA	DU	66.00	12.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	LATIGO THOUSAND OAKS	DU	66.00	16.00	
2	LAUREL TULARE	DU	66.00	12.00	
3	LAWNDALE INGLEWOOD	DU	16.00	4.00	
4	LAYFAIR COVINA	DU	66.00	12.00	
5	LAYFAIR COVINA	DU	66.00	4.00	
6	LEHMAN OXNARD	DU	66.00	12.00	
7	LEMON COVE VISALIA	DU	66.00	12.00	
8	LENNOX INGLEWOOD	DU	66.00	16.00	
9	LENNOX INGLEWOOD	DU	16.00	4.00	
10	LEVY VENTURA	DU	66.00	16.00	
11	LIBERTY VISALIA	DU	66.00	12.00	
12	LIMESTONE EL TORO	DU	66.00	12.00	
13	LINDEN LONG BEACH	DU	12.00	4.00	
14	LINDSAY PORTERVILLE	DU	66.00	12.00	
15	LINDSAY PORTERVILLE	DU	66.00	4.00	
16	LIQUID IRWINDALE	DU	66.00	4.00	
17	LITTLE LAKE RIDGECREST	DU	33.00	12.00	
18	LIVE OAK COVINA	DU	66.00	12.00	
19	LOCKHEED SAUGUS	DU	66.00	16.00	
20	LOCKHEED SAUGUS	DU	66.00	12.00	
21	LOCUST LONG BEACH	DU	12.00	4.00	
22	LOCUST LONG BEACH	DU	4.00	4.00	
23	LONGDON COMPTON	DU	16.00	4.00	
24	LORAIN LANCASTER	DU	66.00	12.00	
25	LOS CERRITOS LONG BEACH	DU	66.00	12.00	
26	LOS CERRITOS LONG BEACH	DU	12.00	4.00	
27	LUCAS LONG BEACH	DU	66.00	12.00	
28	LUCAS LONG BEACH	DU	66.00	4.00	
29	LUCERNE HI DESERT	DU	33.00	12.00	
30	LUNADA REDONDO	DU	16.00	4.00	
31	LYNWOOD COMPTON	DU	16.00	4.00	
32	MACARTHUR HUNTINGTON BEACH	DU	66.00	12.00	
33	MACNEIL BURBANK	DU	66.00	12.00	
34	MADRID REDONDO	DU	16.00	4.00	
35	MALIBU THOUSAND OAKS	DU	66.00	16.00	
36	MANHATTAN REDONDO	DU	16.00	4.00	
37	MARASCHINO INLAND	DU	115.00	12.00	
38	MARINE SANTA MONICA	DU	66.00	16.00	
39	MARION FULLERTON	DU	66.00	12.00	
40	MARIPOSA DELANO	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	MARYMOUNT REDONDO	DU	66.00	16.00	
2	MAXWELL SAN JACINTO	DU	115.00	12.00	
3	MAYBERRY SAN JACINTO	DU	115.00	12.00	
4	MAYFLOWER MONROVIA	DU	16.00	4.00	
5	MAYWOOD COMPTON	DU	16.00	4.00	
6	MENTONE INLAND	DU	115.00	12.00	
7	MERCED COVINA	DU	66.00	12.00	
8	MICHILLINDA MONROVIA	DU	16.00	4.00	
9	MIDWIND LANCASTER	DU	66.00	12.00	
10	MILLIKEN INLAND	DU	66.00	12.00	
11	MINNEOLA HI DESERT	DU	33.00	12.00	
12	MISSILE POINT MUGU	DU	66.00	16.00	
13	MOBILOIL TORRANCE	DU	66.00	12.00	
14	MODENA SANTA ANA	DU	66.00	12.00	
15	MODOC SANTA BARBARA	DU	16.00	4.00	
16	MONETA REDONDO	DU	16.00	4.00	
17	MONOLITH LANCASTER	DU	66.00	12.00	
18	MONROVIA MONROVIA	DU	16.00	4.00	
19	MONTEBELLO MONTEBELLO	DU	16.00	4.00	
20	MONTECITO SANTA BARBARA	DU	16.00	4.00	
21	MOOG TORRANCE	DU	66.00	12.00	
22	MOONEY VISALIA	DU	12.00	4.00	
23	MORAGA TEMECULA	DU	115.00	12.00	
24	MORENO MORENO VALLEY	DU	115.00	12.00	
25	MORNINGSIDE INGLEWOOD	DU	16.00	4.00	
26	MORRO EL TORO	DU	66.00	12.00	
27	MORRO EL TORO	DU	66.00	12.00	
28	MOULTON EL TORO	DU	66.00	12.00	
29	MOUNTAIN PASS HI DESERT	DU	115.00	33.00	
30	MOUNTAIN PASS HI DESERT	DU	33.00	12.00	
31	MOVIE CULVER CITY	DU	66.00	16.00	
32	MT. VERNON INLAND	DU	33.00	4.00	
33	MURPHY WHITTIER	DU	66.00	12.00	
34	MURRIETTA 2 SAN JACINTO	DU	33.00	12.00	
35	MUSCOY INLAND	DU	33.00	4.00	
36	NAOMI COMPTON	DU	16.00	4.00	
37	NAPLES LONG BEACH	DU	12.00	4.00	
38	NAROD ONTARIO	DU	66.00	12.00	
39	NARROWS WHITTIER	DU	66.00	12.00	
40	NAVY MOLE LONG BEACH	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	NEENACH LANCASTER	DU	66.00	12.00	
2	NELSON SAN JACINTO	DU	115.00	33.00	
3	NELSON SAN JACINTO	DU	115.00	12.00	
4	NEPTUNE LONG BEACH	DU	66.00	12.00	
5	NEPTUNE LONG BEACH	DU	66.00	4.00	
6	NEWBURY THOUSAND OAKS	DU	66.00	16.00	
7	NEWCOMB SAN JACINTO	DU	115.00	12.00	
8	NEWHALL SAN FERNANDO	DU	66.00	16.00	
9	NEWMARK MONTEBELLO	DU	66.00	16.00	
10	NEWMARK MONTEBELLO	DU	66.00	4.00	
11	NEWMARK MONTEBELLO	DU	16.00	4.00	
12	NIGUEL EL TORO	DU	66.00	12.00	
13	NIGUEL EL TORO	DU	66.00	4.00	
14	NOGALES COVINA	DU	66.00	12.00	
15	NOLA COMPTON	DU	66.00	16.00	
16	NORCO ONTARIO	DU	12.00	4.00	
17	NORSEAL SEAL BEACH	DU	66.00	12.00	
18	NORTH INTAKE BLYTHE	DU	33.00	12.00	
19	NORTH MUROC RIDGECREST	DU	33.00	12.00	
20	NORTH OAKS SAN FERNANDO	DU	66.00	16.00	
21	NORTHROP HAWTHORNE	DU	66.00	4.00	
22	NORTHWIND LANCASTER	DU	66.00	12.00	
23	NORWELD BREA	DU	66.00	12.00	
24	NUEVO SAN JACINTO	DU	33.00	12.00	
25	NUGGET TWENTY-NINE PALMS	DU	33.00	25.00	
26	OAK GROVE VISALIA	DU	66.00	12.00	
27	OAK PARK THOUSAND OAKS	DU	66.00	16.00	
28	OASIS LANCASTER	DU	66.00	12.00	
29	OCEAN PARK SANTA MONICA	DU	16.00	4.00	
30	OCEANVIEW HUNTINGTON BEACH	DU	66.00	12.00	
31	OCTOL TULARE	DU	66.00	12.00	
32	OJAI VENTURA	DU	66.00	16.00	
33	OJAI VENTURA	DU	66.00	16.00	
34	OLDFIELD LONG BEACH	DU	12.00	4.00	
35	OLIVE LAKE BLYTHE	DU	33.00	12.00	
36	OLYMPIC SANTA MONICA	DU	16.00	4.00	
37	ONEILL RANCHO SANTA MARGARITA	DU	66.00	12.00	
38	ONSHORE ELLWOOD	DU	66.00	12.00	
39	ONTARIO ONTARIO	DU	12.00	4.00	
40	ORANGE SANTA ANA	DU	66.00	12.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	ORCOSAN FOUNTAIN VALLEY	DU	66.00	12.00	
2	ORDWAY HI DESERT	DU	33.00	12.00	
3	ORO GRANDE HI DESERT	DU	33.00	12.00	
4	ORTEGA SANTA BARBARA	DU	66.00	33.00	2.40
5	OXNARD VENTURA	DU	16.00	4.00	
6	PACKAGE INDUSTRY	DU	66.00	4.00	
7	PACLINE CARSON	DU	66.00	2.00	
8	PALM CANYON PALM SPRINGS	DU	33.00	12.00	
9	PALM CANYON PALM SPRINGS	DU	33.00	4.00	
10	PALM SPRINGS PALM SPRINGS	DU	33.00	4.00	
11	PALM VILLAGE PALM SPRINGS	DU	33.00	12.00	
12	PALM VILLAGE PALM SPRINGS	DU	33.00	5.00	
13	PALMDALE LANCASTER	DU	66.00	12.00	
14	PALOS VERDES REDONDO	DU	16.00	4.00	
15	PAPER FULLERTON	DU	66.00	4.00	
16	PAPERMATE SANTA MONICA	DU	66.00	16.00	
17	PARKWOOD FULLERTON	DU	66.00	12.00	
18	PASSONS WHITTIER	DU	66.00	12.00	
19	PAUBA SAN JACINTO	DU	115.00	12.00	
20	PAULARINO HUNTINGTON BEACH	DU	12.00	4.00	
21	PEARL SANTA MONICA	DU	16.00	4.00	
22	PECHANGA SAN JACINTO	DU	115.00	33.00	
23	PECHANGA SAN JACINTO	DU	115.00	12.00	
24	PEDLEY ONTARIO	DU	66.00	12.00	
25	PEERLESS RIDGECREST	DU	33.00	12.00	
26	PEPPER INLAND	DU	115.00	12.00	
27	PEREZ ONTARIO	DU	33.00	4.00	
28	PERRY REDONDO	DU	16.00	4.00	
29	PERRY REDONDO	DU	16.00	4.00	
30	PEYTON ONTARIO	DU	66.00	12.00	
31	PHARMACY THOUSAND OAKS	DU	66.00	16.00	
32	PHELAN HI DESERT	DU	115.00	33.00	
33	PHELAN HI DESERT	DU	115.00	12.00	
34	PICO LONG BEACH	DU	66.00	12.00	
35	PIERPONT VENTURA	DU	16.00	4.00	
36	PIONEER WHITTIER	DU	66.00	12.00	
37	PIONEER WHITTIER	DU	12.00	4.00	
38	PIPE ETIWANDA	DU	66.00	12.00	
39	PIUTE LANCASTER	DU	66.00	12.00	
40	PIXLEY DELANO	DU	66.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	PIXLEY DELANO	DU	66.00	12.00	
2	PLACENTIA FULLERTON	DU	66.00	12.00	
3	PLASTIC CHINO	DU	66.00	12.00	
4	PLAYA SANTA BARBARA	DU	16.00	4.00	
5	POLARIS EL SEGUNDO	DU	66.00	4.00	
6	POMONA COVINA	DU	12.00	4.00	
7	POPLAR PORTERVILLE	DU	66.00	12.00	
8	PORTER SAN FERNANDO	DU	16.00	4.00	
9	PORTERVILLE PORTERVILLE	DU	66.00	12.00	
10	PORTERVILLE PORTERVILLE	DU	66.00	4.00	
11	POTRERO THOUSAND OAKS	DU	66.00	16.00	
12	POWERINE SANTA FE SPRINGS	DU	66.00	12.00	
13	PROCTOR COVINA	DU	66.00	12.00	
14	PROTEIN TULARE	DU	66.00	12.00	
15	PUENTE COVINA	DU	66.00	12.00	
16	PUREWATER REDLANDS	DU	115.00	4.00	
17	QUARTZ HILL LANCASTER	DU	66.00	12.00	
18	QUINN DELANO	DU	66.00	12.00	
19	RAILROAD COVINA	DU	66.00	12.00	
20	RAMONA MONTEBELLO	DU	66.00	4.00	
21	RANCHO HI DESERT	DU	33.00	12.00	
22	RANDALL FOOTHILL	DU	66.00	12.00	
23	RANDOLPH COMPTON	DU	66.00	16.00	
24	RANDBURG RIDGECREST	DU	33.00		
25	RAVENDALE MONTEBELLO	DU	66.00	16.00	
26	RAVENDALE MONTEBELLO	DU	66.00	4.00	
27	RECOVERY HUNTINGTON BEACH	DU	66.00	12.00	
28	RECTIFIER TEMECULA	DU	115.00	33.00	
29	REDLANDS INLAND	DU	66.00	12.00	
30	REDLANDS INLAND	DU	66.00	4.00	
31	REDMAN LANCASTER	DU	66.00	12.00	
32	REDONDO REDONDO	DU	16.00	4.00	
33	REDUCTION ETIWANDA	DU	66.00	4.00	
34	REFINERY CARSON	DU	66.00	12.00	
35	REFUSE COMMERCE	DU	66.00	12.00	
36	RENO INDUSTRY	DU	66.00	4.00	
37	RENWIND PALM SPRINGS	DU	115.00	12.00	
38	REPETTO MONTEBELLO	DU	66.00	16.00	
39	REPETTO MONTEBELLO	DU	66.00	4.00	
40	RIALTO FOOTHILL	DU	33.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	RIALTO Foothill	DU	33.00	4.00	
2	RIDGECREST RIDGECREST	DU	33.00	5.00	
3	RINDGE THOUSAND OAKS	DU	16.00	4.00	
4	RINGMILL PARAMOUNT	DU	66.00	4.00	
5	RIPLEY BLYTHE	DU	33.00	12.00	
6	RITEAID LANCASTER	DU	66.00	12.00	
7	RITTER RANCH PALMDALE	DU	66.00	12.00	
8	RIVERA WHITTIER	DU	12.00	4.00	
9	RIVERWAY VISALIA	DU	66.00	12.00	
10	ROADWAY HI DESERT	DU	115.00	12.00	
11	ROCKAIR PALMDALE	DU	66.00	12.00	
12	ROCKET TEST BORON	DU	115.00	33.00	
13	ROLLING HILLS REDONDO	DU	66.00	16.00	
14	ROLLING HILLS REDONDO	DU	66.00	4.00	
15	ROSAMOND LANCASTER	DU	66.00	16.00	
16	ROSAMOND LANCASTER	DU	66.00	12.00	
17	ROSECRANS EL SEGUNDO	DU	66.00	16.00	
18	ROSEMEAD MONTEBELLO	DU	66.00	16.00	
19	ROYAL SIMI VALLEY	DU	66.00	16.00	
20	RUBIDOUX RUBIDOUX	DU	33.00	12.00	
21	RUBIDOUX RUBIDOUX	DU	33.00	4.00	
22	RUNNING SPRINGS ARROWHEAD	DU	33.00	12.00	
23	RUSH MONTEBELLO	DU	66.00	16.00	
24	SAN ANTONIO COVINA	DU	66.00	12.00	
25	SAN DIMAS COVINA	DU	66.00	12.00	
26	SAN FERNANDO SAN FERNANDO	DU	66.00	16.00	
27	SAN GABRIEL MONTEBELLO	DU	66.00	4.00	
28	SAN JACINTO SAN JACINTO	DU	33.00	5.00	
29	SAN MARCOS SANTA BARBARA	DU	66.00	16.00	
30	SAN MARINO MONROVIA	DU	16.00	4.00	
31	SAN MIGUEL VENTURA	DU	66.00	16.00	
32	SAN VICENTE SANTA MONICA	DU	16.00	4.00	
33	SANGAR MONROVIA	DU	16.00	4.00	
34	SANTA BARBARA SANTA BARBARA	DU	66.00	16.00	
35	SANTA BARBARA SANTA BARBARA	DU	66.00	4.00	
36	SANTA FE SPRINGS WHITTIER	DU	66.00	12.00	
37	SANTA MONICA SANTA MONICA	DU	66.00	16.00	
38	SANTA MONICA SANTA MONICA	DU	66.00	4.00	
39	SANTA ROSA PALM SPRINGS	DU	115.00	33.00	
40	SANTA ROSA PALM SPRINGS	DU	115.00	12.00	

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			Primary (c)	Secondary (d)	Tertiary (e)
1	SANTA SUSANA THOUSAND OAKS	DU	66.00	16.00	
2	SANTEE INDUSTRY	DU	66.00	12.00	
3	SATICOY VENTURA	DU	66.00	16.00	
4	SAVAGE HESPERIA	DU	115.00	12.00	
5	SAWTELLE SANTA MONICA	DU	66.00	16.00	
6	SEABRIGHT LONG BEACH	DU	66.00	12.00	
7	SEARLES RIDGECREST	DU	115.00	33.00	
8	SECOND AVENUE BLYTHE	DU	33.00	12.00	
9	SEPULVEDA INGLEWOOD	DU	66.00	16.00	
10	SEPULVEDA INGLEWOOD	DU	16.00	4.00	
11	SHANDIN INLAND	DU	115.00	12.00	
12	SHARON MONROVIA	DU	16.00	4.00	
13	SHAWNEE HUNTINGTON BEACH	DU	66.00	12.00	
14	SHELLSOM SOMIS	DU	66.00	2.00	
15	SHELLWATT CARSON	DU	66.00	12.00	
16	SHULTZ SOUTH GATE	DU	66.00	16.00	
17	SHUTTLE LANCASTER	DU	66.00	12.00	
18	SIERRA MADRE MONROVIA	DU	16.00	4.00	
19	SIGNAL HILL LONG BEACH	DU	66.00	12.00	
20	SIGNAL HILL LONG BEACH	DU	12.00	4.00	
21	SILVER SPUR PALM SPRINGS	DU	33.00	12.00	
22	SIMPSON PAPER POMONA	DU	66.00	12.00	
23	SIXTEENTH STREET INLAND	DU	33.00	12.00	
24	SKYLARK SAN JACINTO	DU	115.00	12.00	
25	SLATER HUNTINGTON BEACH	DU	66.00	12.00	
26	SMILEY INLAND	DU	12.00	4.00	
27	SOCO HUNTINGTON BEACH	DU	66.00	33.00	
28	SOLEMINT SAN FERNANDO	DU	66.00	16.00	
29	SOMERSET COMPTON	DU	66.00	12.00	
30	SOMERSET COMPTON	DU	66.00	4.00	
31	SOMIS VENTURA	DU	66.00	16.00	
32	SONY CULVER CITY	DU	66.00	16.00	
33	SOQUEL CHINO HILLS	DU	66.00	12.00	
34	SOUTH GATE COMPTON	DU	16.00	4.00	
35	SOUTHBASE E.A.F.B.	DU	115.00	33.00	
36	SOUTHPAC NORWALK	DU	66.00	2.00	
37	SOUTHWIND LANCASTER	DU	66.00	12.00	
38	SPACE REDONDO BEACH	DU	66.00	4.00	
39	STADIUM LONG BEACH	DU	66.00	12.00	
40	STADLER SAN JACINTO	DU	115.00	12.00	

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	STANHILL INGLEWOOD	DU	66.00	12.00	
2	STATE STREET LONG BEACH	DU	66.00	12.00	
3	STATE STREET LONG BEACH	DU	66.00	12.00	
4	STENT TEMECULA	DU	115.00	12.00	
5	STETSON SAN JACINTO	DU	115.00	12.00	
6	STEWART WHITTIER	DU	66.00	12.00	
7	STIRRUP REDONDO	DU	16.00	4.00	
8	STODDARD INLAND	DU	33.00	4.00	
9	STRATHMORE PORTERVILLE	DU	66.00	12.00	
10	SULLIVAN SANTA ANA	DU	66.00	12.00	
11	SULLIVAN SANTA ANA	DU	66.00	4.00	
12	SUN CITY SAN JACINTO	DU	115.00	12.00	
13	SUNNY DUNES PALM SPRINGS	DU	33.00	4.00	
14	SUNNYSIDE LONG BEACH	DU	66.00	12.00	
15	SUNNYSIDE LONG BEACH	DU	66.00	4.00	
16	TAHITI SANTA MONICA	DU	66.00	16.00	
17	TAHITI SANTA MONICA	DU	66.00	12.00	
18	TALBERT SANTA ANA	DU	66.00	12.00	
19	TAMARISK PALM SPRINGS	DU	115.00	12.00	
20	TAPIA THOUSAND OAKS	DU	66.00	16.00	
21	TEAM WESTMINSTER	DU	66.00	12.00	
22	TELEGRAPH WHITTIER	DU	66.00	12.00	
23	TEMPLE MONROVIA	DU	16.00	4.00	
24	TENAJA MURRIETA	DU	115.00	12.00	
25	TENNESSEE INLAND	DU	66.00	12.00	
26	TERRA BELLA PORTERVILLE	DU	66.00	12.00	
27	TERRACE MONTEBELLO	DU	16.00	4.00	
28	THORNHILL PALM SPRINGS	DU	115.00	12.00	
29	THOUSAND OAKS THOUSAND OAKS	DU	66.00	16.00	
30	THREE M CAMARILLO	DU	66.00	4.00	
31	THREE RIVERS VISALIA	DU	66.00	12.00	
32	THRUST CHATSWORTH	DU	66.00	4.00	
33	THUMS A LONG BEACH	DU	66.00	4.00	
34	THUMS B LONG BEACH	DU	66.00	4.00	
35	THUMS C LONG BEACH	DU	66.00	4.00	
36	THUMS D LONG BEACH	DU	66.00	4.00	
37	THUNDERBIRD PALM SPRINGS	DU	33.00	5.00	
38	TIDELANDS LONG BEACH	DU	66.00	12.00	
39	TIEFORT HI DESERT	DU	115.00	33.00	
40	TIMOTEO INLAND	DU	66.00	12.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	TIPPECANOE INLAND	DU	12.00	4.00	
2	TIPTON TULARE	DU	66.00	12.00	
3	TOPANGA THOUSAND OAKS	DU	16.00	4.00	
4	TOPAZ REDONDO	DU	66.00	4.00	
5	TORRANCE REDONDO	DU	66.00	16.00	
6	TORREY PIRU	DU	66.00	16.00	
7	TORTILLA HI DESERT	DU	115.00	33.00	
8	TORTILLA HI DESERT	DU	115.00	12.00	
9	TOYOTA LONG BEACH	DU	66.00	12.00	
10	TRASK SANTA ANA	DU	66.00	12.00	
11	TRONA RIDGECREST	DU	33.00	12.00	
12	TROPHY COVINA	DU	66.00	12.00	
13	TROPHY COVINA	DU	66.00	12.00	
14	TULARE TULARE	DU	66.00	12.00	
15	TULARE TULARE	DU	66.00	4.00	
16	TWENTYNINE PALMS TWENTY-NINE PALMS	DU	33.00	12.00	
17	TWENTYNINE PALMS TWENTY-NINE PALMS	DU	33.00	5.00	
18	UNIOIL OXNARD	DU	66.00	16.00	
19	UNIVERSAL UNIVERSAL CITY	DU	66.00	12.00	
20	UPLAND FOOTHILL	DU	66.00	12.00	
21	UPLAND FOOTHILL	DU	66.00	4.00	
22	VAIL MONTEBELLO	DU	66.00	16.00	
23	VALDEZ THOUSAND OAKS	DU	66.00	16.00	
24	VALENCIA INLAND	DU	12.00	4.00	
25	VARWIND MOJAVE	DU	66.00	12.00	
26	VARWIND MOJAVE	DU	12.00	1.00	
27	VEGAS SANTA BARBARA	DU	66.00	16.00	
28	VENICE HILL VISALIA	DU	66.00	12.00	
29	VENIDA VISALIA	DU	66.00	12.00	
30	VENTURA VENTURA	DU	16.00	4.00	
31	VENWIND PALM SPRINGS	DU	115.00	12.00	
32	VERA SANTA ANA	DU	66.00	12.00	
33	VERDANT BLYTHE	DU	33.00	12.00	
34	VICTORIA REDONDO	DU	66.00	16.00	
35	VICTORVILLE HI DESERT	DU	33.00	12.00	
36	VICTORVILLE HI DESERT	DU	33.00	4.00	
37	VISALIA VISALIA	DU	66.00	12.00	
38	VISALIA VISALIA	DU	66.00	4.00	
39	WABASH MONTEBELLO	DU	66.00	16.00	
40	WAKEFIELD VENTURA	DU	66.00	16.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	WALKER BASIN KERNVILLE	DU	66.00	12.00	
2	WALTERIA REDONDO	DU	66.00	16.00	
3	WALTERIA REDONDO	DU	66.00	4.00	
4	WASHINGTON SANTA ANA	DU	66.00	12.00	
5	WASTEWATER OXNARD	DU	66.00	16.00	
6	WATSON COMPTON	DU	66.00	12.00	
7	WAVE HUNTINGTON BEACH	DU	66.00	12.00	
8	WAVE HUNTINGTON BEACH	DU	12.00	4.00	
9	WEBCO PARAMOUNT	DU	66.00	4.00	
10	WELDON KERNVILLE	DU	66.00	12.00	
11	WESBASIN EL SEGUNDO	DU	66.00	16.00	
12	WEST BARSTOW HI DESERT	DU	33.00	4.00	
13	WEST RIVERSIDE ONTARIO	DU	33.00	12.00	
14	WESTEX SIGNAL HILL	DU	66.00	12.00	
15	WESTGATE WHITTIER	DU	12.00	4.00	
16	WESTHILL EL SEGUNDO	DU	66.00	16.00	
17	WESTPAC GORMAN	DU	66.00	4.00	
18	WHEATLAND DELANO	DU	66.00	12.00	
19	WHIPPLE BLYTHE	DU	66.00	33.00	
20	WHITEWATER PALM SPRINGS	DU	33.00	4.00	
21	WILDE HI DESERT	DU	33.00	4.00	
22	WILSONA LANCASTER	DU	66.00	12.00	
23	WIMBLEDON FOOTHILL	DU	66.00	12.00	
24	WINDSOR HILLS INGLEWOOD	DU	66.00	16.00	
25	WINDSOR HILLS INGLEWOOD	DU	16.00	4.00	
26	WOODRUFF COMPTON	DU	12.00	4.00	
27	WOODVILLE PORTERVILLE	DU	66.00	12.00	
28	WRIGHTWOOD HI DESERT	DU	33.00	12.00	
29	WRIGHTWOOD HI DESERT	DU	12.00	2.00	
30	YERMO HI DESERT	DU	33.00	12.00	
31	YORBA LINDA FULLERTON	DU	66.00	12.00	
32	YUCAIPA INLAND	DU	66.00	12.00	
33	YUCCA TWENTY-NINE PALMS	DU	115.00	12.00	
34	YUKON INGLEWOOD	DU	66.00	16.00	
35	ZUMA THOUSAND OAKS	DU	16.00	4.00	
36					
37					
38					
39					
40	Rounding Adjustment due to				

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVA)		
			Primary (c)	Secondary (d)	Tertiary (e)
1	FOSS Software Rounding in Column F				
2					
3					
4	Total		74123.00	15866.00	175.30
5					
6	762 DU 30974.714				
7	60 TA 36977.38				
8	133 TU 30947.07				
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
681	6					1
5	1					2
530	2					3
530	3					4
61	5		ADDED 75MVA PEAKER I			5
28	1		ADDED 75MVA PEAKER I			6
36	3	1				7
6	3					8
810	3					9
234	9	1	ADDED 75MVA PEAKER I			10
332	2					11
99	3					12
84	3					13
150	10		CONDENSER	1	60	14
11	1		3 PHASE PAD MT. GENE	1		15
280	1					16
840	3					17
2260	6					18
810	3	1				19
424	2					20
133	1					21
9	3	1				22
120	3					23
280	1					24
560	2					25
82	4					26
1033	6	1				27
102	1					28
810	3					29
44	2					30
990	4					31
56	2					32
28	1					33
430	2					34
11	3	1				35
172	5					36
33	1					37
28	2					38
14	1					39
840	3					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
560	2					1
73	3					2
530	2					3
56	2					4
50	3	1				5
560	2					6
780	3					7
112	2					8
66	3		CONDENSER #1	1	72	9
1120	4					10
56	2		CONDENSER #4	1	60	11
810	3		CONDS. 2-3	2	120	12
44	2		CONDENSER #4	1	72	13
2238	6	1				14
840	3					15
56	2					16
75	3	1	CONDENSER #1	1	72	17
4359	12	1				18
810	3	1				19
28	1		ADDED 75MVA PEAKER I			20
222	2					21
1120	4					22
100	4					23
680	5	1				24
28	2					25
100	1					26
840	3					27
148	7					28
2238	6	1				29
940	3					30
200	3	1				31
51	12	2				32
480	12					33
280	1					34
45	2					35
78	3					36
333	3					37
56	2					38
308	2					39
810	4					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
157	6					1
840	3					2
112	4					3
3237	9		REACTOR	4	180	4
478	7					5
39	3		CONDENSER #1	1	39	6
1736	4					7
73	3					8
200	6					9
560	2					10
162	3					11
112	4					12
560	2					13
56	2					14
840	3					15
100	4					16
2944	9					17
1119	3					18
504	2					19
1060	4					20
60	3					21
560	3		CONDENSER	1	75	22
91	6					23
240	6					24
14	1					25
56	1					26
10	1					27
60	1					28
120	6	1				29
4	5	1				30
						31
120	1					32
122	1					33
49	1					34
134	1					35
133	1	3				36
1	3					37
75	1	1				38
						39
12	3	1				40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
22	1					1
56	2					2
44	2					3
22	1					4
200	6					5
38	3	1				6
16	1					7
28	1					8
250	1					9
990	4					10
56	2					11
28	1					12
40	2					13
75	1		ADDED 75MVA PEAKER I			14
56	2					15
40	3	1	Transformer owned by			16
300	7	1	Transformer owned by			17
3	3	1				18
2	1					19
4	3	1				20
24	4					21
36	6	1				22
10	1					23
18	3					24
4	1					25
180	2	1				26
1	1					27
75	1		ADDED 75MVA PEAKER I			28
14	1					29
1	3					30
3	1					31
1650	2	1	56% OWNER			32
12	3					33
	3					34
28	1					35
100	1					36
1533	3	1	15.8% OWNER			37
126			15.8% OWNER			38
1533	3		15.8% OWNER			39
126			15.8% OWNER			40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
1533	3		15.8% OWNER			1
126			15.8% OWNER			2
14	1					3
8	6					4
28	1					5
5	1					6
10	1					7
1	3					8
6	3	1				9
10	1					10
4	1					11
4	1					12
14	1	1				13
2	3	1				14
10	1					15
44	2					16
22	1					17
14	1					18
14	1					19
6	4					20
333	3					21
56	2					22
2460	2	1				23
22	1					24
10	1					25
	3					26
44	2					27
44	2					28
14	1					29
14	1					30
14	1					31
3	3	1				32
50	2					33
14	1					34
2238	6					35
28	2					36
14	1					37
14	1					38
128	5					39
56	2					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
101	4					1
112	4					2
12	6	1				3
12	2					4
56	2					5
139	8					6
9	3	1				7
14	2					8
166	3	1				9
3	1					10
28	1					11
13	1					12
88	4					13
72	3					14
84	3					15
15	6					16
14	1					17
22	1					18
84	3					19
56	2					20
28	1					21
90	4					22
25	2					23
5	2					24
73	3					25
100	4					26
8	1					27
56	2					28
6	3	1				29
2	1					30
76	8					31
3	3	1				32
6	6					33
14	2					34
8	1					35
50	2					36
112	2					37
112	4					38
22	1					39
76	4					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVA) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	3					1
56	2					2
7	1					3
6	3	1				4
75	12	1				5
112	3					6
11	2					7
6	3	1				8
25	1					9
56	2					10
8	3	1				11
48	2					12
28	1					13
3	3	1				14
25	4					15
10	1	1				16
10	1					17
6	3	1				18
138	6					19
38	3					20
6	6	1				21
8	1					22
27	2					23
12	6					24
112	4					25
11	4					26
28	2					27
24	2					28
40	2					29
28	1					30
84	3					31
44	2					32
80	9					33
6	3					34
12	6					35
66	3					36
36	2					37
44	2					38
14	1					39
9	9					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
20	2					1
50	2					2
4	2					3
44	2					4
4	2					5
34	2					6
13	6	1				7
90	4					8
99	3					9
68	5					10
12	6					11
84	3					12
11	2					13
14	1					14
19	2					15
118	5					16
5	3	1				17
73	3					18
44	2					19
25	3					20
28	2					21
120	3					22
3	3					23
72	3					24
45	2					25
56	2					26
4	3	1				27
40	2					28
14	1					29
28	2					30
11	1					31
6	1					32
112	2					33
84	4					34
184	8	2				35
14	1					36
66	3					37
66	3					38
34	6					39
10	6					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
14	2					1
6	3	1				2
14	1					3
56	2					4
99	4					5
12	3	1				6
34	5					7
44	2					8
95	4					9
168	4					10
101	4					11
94	4					12
28	1					13
20	2					14
56	4					15
56	2					16
50	2					17
14	1					18
73	12					19
28	6					20
9	3					21
112	4					22
12	2					23
45	2					24
6	1					25
56	2					26
112	2					27
188	7					28
8	1					29
100	4					30
14	1					31
28	1					32
28	2					33
15	2					34
56	2					35
9	2					36
28	2					37
22	1					38
84	3					39
19	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
175	6					1
116	5					2
68	3					3
24	7					4
42	2					5
28	1					6
23	6					7
15	3	1				8
73	3					9
30	6					10
75	3	1				11
6	3	1				12
56	2					13
14	1					14
6	3	1				15
101	4					16
7	1					17
7	1					18
106	4					19
56	2					20
56	2					21
6	3	1				22
14	1					23
11	2					24
44	2					25
40	2					26
45	2					27
12	4					28
15	2					29
6	3					30
12	1					31
25	2					32
28	1					33
8	3					34
8	1					35
14	1					36
44	2					37
5	6					38
22	1					39
14	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	3					1
23	4					2
38	3					3
56	2					4
9	8					5
10	2					6
25	3					7
28	1					8
112	2					9
45	2					10
8	2					11
10	2					12
5	1					13
11	1					14
100	2					15
56	2					16
2	3					17
62	3					18
73	3					19
44	2					20
87	4					21
6	3					22
30	6	1				23
17	2					24
60	3					25
24	12					26
90	4					27
106	4					28
45	2					29
9	4					30
48	2					31
22	1					32
37	4					33
72	3					34
8	4					35
13	2					36
99	3					37
14	1					38
72	4					39
6	3	1				40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
62	3					1
9	6					2
11	1					3
11	1					4
30	6					5
9	3	1				6
11	1					7
66	3					8
9	3	1				9
8	3	1				10
14	1					11
12	1					12
40	4					13
44	2					14
78	3					15
6	3					16
9	3					17
100	2					18
11	1					19
13	4					20
14	1					21
28	2					22
27	5					23
40	2					24
22	1					25
90	4					26
100	4					27
50	2					28
6	1					29
4	3	1				30
20	6					31
84	3					32
7	6	1				33
28	2					34
8	4		3 PHASE SHIFT AUXILA			35
9	6					36
3	3	1				37
12	3					38
10	2	1				39
45	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	3					1
6	1					2
38	6					3
115	5					4
12	6	1				5
14	1					6
6	3					7
3	3					8
4	1					9
81	4					10
48	2					11
9	3	1				12
6	3	1				13
6	3	1				14
15	3	1				15
6	3					16
24	2					17
56	2					18
7	1					19
31	2					20
9	1					21
50	2					22
50	6	1				23
5	3	1				24
100	4					25
7	4					26
5	1					27
21	2					28
56	3					29
30	2					30
28	2					31
10	4					32
56	2					33
14	1					34
21	2					35
11	2					36
7	1					37
10	1					38
1	3	1				39
48	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
12	6					1
112	4					2
38	6					3
22	1					4
22	1					5
56	2					6
15	6					7
16	1					8
56	2					9
112	2					10
11	6	1				11
150	3	1				12
249	3					13
50	2					14
15	3	1				15
48	2					16
6	3	1				17
56	2					18
101	4					19
78	3					20
5	1					21
252	6					22
4	3	1				23
10	4	2				24
56	2					25
44	2					26
14	2					27
82	4					28
56	2					29
19	3					30
22	1					31
98	4					32
44	2					33
3	2					34
50	2					35
88	4					36
6	6	1				37
20	1	1				38
6	3	1				39
56	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
41	4	1				1
12	6					2
6	3					3
28	3					4
6	3	1				5
28	1					6
6	3	2				7
40	2					8
8	9					9
42	2					10
100	4					11
149	6					12
6	3	1				13
34	4	1				14
1	3	1				15
14	1					16
99	3	1				17
72	3					18
56	2					19
12	1					20
11	1					21
11	1					22
9	6	1				23
3	3	1				24
40	2					25
6	3					26
28	2					27
15	6					28
28	2					29
6	3	1				30
12	6					31
97	4					32
30	2					33
8	3					34
56	2					35
6	3	1				36
84	3					37
56	2					38
81	4					39
20	1	1				40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
22	2					1
95	4					2
67	3					3
11	2					4
18	8					5
28	2					6
62	3					7
14	2					8
14	1					9
112	4					10
11	2					11
22	1					12
168	6					13
56	4					14
12	6	1				15
15	6					16
28	2					17
18	2					18
6	3	1				19
6	3	1				20
7	1					21
5	6	1				22
112	4					23
45	2					24
6	3					25
10	3					26
14	1					27
89	4					28
28	2					29
11	2					30
40	2					31
27	2					32
44	2					33
28	2					34
332	6					35
6	3					36
12	6					37
88	4					38
62	3					39
28	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
15	3	1				1
112	2					2
73	3					3
44	2					4
24	2					5
98	4					6
112	4					7
112	4					8
18	6					9
13	5	1				10
2	1					11
70	3					12
11	1					13
72	3					14
44	2					15
9	3	1				16
28	2					17
5	1					18
100	3	1				19
72	4					20
56	2					21
12	3					22
14	1					23
14	1					24
14	6	1				25
100	4					26
56	3					27
44	2					28
8	2					29
48	2					30
36	5					31
15	3					32
28	1					33
14	2					34
9	2					35
10	4					36
84	3					37
13	1					38
17	4					39
84	4					40

SUBSTATIONS (Continued)

5. Show in columns (l), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.

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			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
56	2					1
11	2					2
3	3	1				3
28	3					4
14	6					5
5	1					6
10	1					7
22	2					8
5	3	1				9
21	2					10
45	2					11
5	3					12
86	4					13
8	3	1				14
22	1					15
14	1					16
72	3					17
44	2					18
56	3					19
28	2					20
9	6					21
56	1					22
84	3					23
56	2					24
150	3	1				25
48	2					26
3	3	1				27
4	6					28
8	1					29
100	4					30
56	2					31
28	1					32
50	2					33
86	4					34
14	2					35
47	2					36
15	2					37
42	2					38
9	3					39
28	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
28	1					1
66	3					2
14	1					3
6	5	1				4
115	2					5
12	6					6
38	4					7
8	3	1				8
68	4					9
9	6	2				10
100	4					11
28	1					12
44	2					13
22	1					14
56	2					15
28	1					16
50	2					17
19	3	1				18
88	4					19
32	2					20
44	2					21
100	4					22
54	12					23
14	6	1				24
84	4					25
9	3	1				26
22	1					27
20	1					28
94	2					29
12	6					30
6	3	1				31
12	6					32
13	1					33
14	1					34
14	1					35
8	1					36
22	1					37
84	3					38
6	3					39
10	1					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
9	3					1
5	3					2
3	3	1				3
14	1					4
6	1					5
20	1					6
28	1					7
12	12					8
56	2					9
28	2					10
12	1					11
27	3					12
50	2					13
9	3	1				14
14	1					15
10	3					16
19	3					17
86	4					18
106	4					19
11	1					20
23	3					21
11	2					22
100	4					23
100	4					24
70	3					25
56	2					26
24	2					27
5	3					28
44	4					29
9	3	1				30
66	3					31
6	3	1	NUCLEAR REACTOR 400	1		32
6	3	1				33
67	10					34
12	6	1				35
95	5	1				36
56	2					37
12	2					38
100	2					39
101	4					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
100	4					1
14	1					2
44	2					3
106	4					4
22	2					5
38	6					6
33	4					7
6	3	1				8
89	4					9
6	6					10
84	3					11
9	6					12
50	3					13
15	3					14
112	4					15
22	1					16
100	4					17
6	3	1				18
14	2					19
6	3					20
28	2					21
46	1					22
28	2					23
73	3					24
56	3					25
6	1					26
9	3	1				27
56	2					28
44	2					29
12	6					30
28	2					31
14	1					32
56	2					33
12	6	1				34
28	1					35
9	3					36
14	1					37
45	2					38
81	6					39
112	4					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
56	2					1
28	1					2
28	1					3
14	1					4
101	4					5
68	3					6
21	2					7
37	2					8
21	9					9
52	4	1				10
6	3					11
28	1					12
12	2					13
62	3					14
15	6					15
10	1					16
10	1					17
14	3					18
101	4					19
28	2					20
45	2					21
88	4					22
6	6					23
56	2					24
56	2					25
39	7	1				26
7	1					27
45	2					28
112	4					29
13	1					30
9	3	1				31
5	1					32
42	2					33
45	2					34
45	2					35
45	2					36
6	3					37
22	1					38
56	2					39
56	4					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
6	6					1
22	2					2
6	6					3
25	2					4
84	4					5
11	1					6
106	2					7
56	2					8
12	1					9
67	4					10
6	3	1				11
28	1					12
45	2					13
106	4					14
3	3	1				15
21	2					16
7	1					17
16	1					18
22	2					19
67	3					20
14	2					21
106	4					22
32	4					23
4	2					24
10	1					25
13	2					26
50	2					27
44	2					28
56	2					29
9	9	1				30
50	2					31
40	2					32
5	1					33
48	4					34
23	2					35
5	3	1				36
43	2					37
12	9	1				38
18	6	1				39
56	2					40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
45	3					1
65	3					2
9	1					3
45	2					4
14	1					5
24	9					6
42	2					7
8	6					8
22	1					9
9	3					10
14	1					11
249	3					12
14	1					13
11	1					14
6	3	1				15
28	2					16
38	2					17
13	3					18
27	3	1				19
1000	1					20
182	3					21
3	6					22
72	3					23
28	2					24
11	9					25
15	4					26
10	6					27
28	2					28
38	3	1				29
5	1					30
84	3					31
101	4					32
45	2					33
72	5					34
5	3					35
						36
						37
						38
						39
						40

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
-11						1
						2
						3
98899	2761	147		15	750	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
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						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 426.3 Line No.: 16 Column: i
Transformers owned by U.S. Government.

Schedule Page: 426.3 Line No.: 17 Column: i
Transformers owned by U.S. Government.

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	Non-power Goods or Services Provided by Affiliated			
2	Accounts Receivable from Associated Companies	Edison International	146	51,802,698
3	Donations	Edison International	426.1xx	16,800,555
4	Expend - Certain Civic,Political & Related Activ	Edison International	426.4xx	4,029,647
5	Other Deductions	Edison International	426.5xx	1,652,415
6	Dividends Declared	Edison International	438	300,000,000
7	Admin. and Gen Salaries/Office Supplies And Exp	Edison International	920/921	405,842
8	Outside Services Employed	Edison International	923	3,975,435
9	Directors Cost	Edison International	930.2	2,923,046
10	Rent	Edison International	931	22,809
11				
12	TOTAL:			381,612,447
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Other Special Funds	Edison International	128.5	3,757
22	Accounts Receivable from Associated Companies	Edison International	146	-108,156,412
23	Other Deferred Credits	Edison International	253	-345,434
24	Regulatory Debits	Edison International	407.3	279,917
25	Taxes Other Than Inc.Taxes, Utility Op Income	Edison International	408.1xx	74,468
26	Donations	Edison International	426.1xx	64,909
27	Expend - Certain Civic,Political & Related Activ	Edison International	426.4xx	-24,983
28	Other Deductions	Edison International	426.5xx	474,630
29	Other Electric Revenues	Edison International	456	385,542
30	Miscellaneous Transmission Expense	Edison International	566	757
31	Supervision Major Only	Edison International	907	
32	Admin. and Gen Salaries/Office Supplies And Exp	Edison International	920/921	2,224,415
33	Outside Services Employed	Edison International	923	503,885
34	Injuries and Damages	Edison International	925	13,846
35	Employee Pension and Benefits	Edison International	926	3,550,252
36	Corporate Governance & Procurement Expense	Edison International	930.2	2,308
37				
38				
39	TOTAL:			-100,948,143
40				
41				
42				
1	Non-power Goods or Services Provided by Affiliated			
2				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Accounts Receivable from Associated Companies	Edison Mission Group	146	238
22	Taxes Other Than Inc.Taxes, Utility Op Income	Edison Mission Group	408.1xx	4,885
23	Donations	Edison Mission Group	426.1xx	1,027
24	Other Electric Revenues	Edison Mission Group	456	25,554
25	Admin. and Gen Salaries/Office Supplies And Exp	Edison Mission Group	920/921	77,210
26	Outside Services Employed	Edison Mission Group	923	735
27	Injuries and Damages	Edison Mission Group	925	91,406
28	Employee Pension and Benefits	Edison Mission Group	926	15,893
29	Corporate Governance	Edison Mission Group	930.2	2,224
30				
31	TOTAL:			219,172
32				
33	Accounts Receivable from Associated Companies	Edison Capital	146	34,030
34	Taxes Other Than Inc.Taxes, Utility Op Income	Edison Capital	408.1xx	26,972
35	Donations	Edison Capital	426.1xx	35,948
36	Other Electric Revenues	Edison Capital	456	133,318
37	Admin. and Gen Salaries/Office Supplies And Exp	Edison Capital	920/921	411,586
38	Outside Services Employed	Edison Capital	923	396,050
39	Injuries and Damages	Edison Capital	925	5,170
40	Employee Pension and Benefits	Edison Capital	926	156,391
41	Corporate Governance	Edison Capital	930.2	10,948
42	TOTAL:			1,210,413
1	Non-power Goods or Services Provided by Affiliated			
2				
3				
4				

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is \$250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Non-power Goods or Services Provided for Affiliate			
21	Accounts Receivable from Associated Companies	Edison Mission Energy	146	257,488,957
22	Regulatory Debit	Edison Mission Energy	407.3	844,849
23	Taxes Other Than Inc.Taxes, Utility Op Income	Edison Mission Energy	408.1xx	313,684
24	Donations	Edison Mission Energy	426.1xx	392,266
25	Other Electric Revenues	Edison Mission Energy	456	1,248,239
26	Admin. and Gen Salaries/Office Supplies And Exp	Edison Mission Energy	920/921	4,385,709
27	Outside Services Employed	Edison Mission Energy	923	1,911,761
28	Injuries and Damages	Edison Mission Energy	925	57,647
29	Employee Pension and Benefits	Edison Mission Energy	926	17,985,505
30	Corporate Governance	Edison Mission Energy	930.2	357,055
31				
32	TOTAL:			284,985,672
33				
34				
35	Taxes Other Than Inc.Taxes, Utility Op Income		408.1xx	
36	Other Electric Revenues		426.1xx	
37	Admin. and Gen Salaries/Office Supplies And Exp		920/921	
38	Outside Services Employed		923	
39	Injuries and Damages		925	
40	Employee Pension and Benefits		926	1,732,103
41				
42	TOTAL:			1,732,103

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 2 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 3 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 4 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 5 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429 Line No.: 6 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 7 Column:

Directly Charged: All costs associated with services are billed to the utility.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 8 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429 Line No.: 9 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429 Line No.: 10 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 21 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 22 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 23 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 24 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 25 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 26 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 27 Column:

Directly Charged: All costs associated with services are billed to the utility.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Schedule Page: 429 Line No.: 28 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 29 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 30 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 31 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429 Line No.: 32 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 33 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 34 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 35 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429 Line No.: 36 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429.1 Line No.: 21 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429.1 Line No.: 22 Column:

Directly Charged: All costs associated with services are billed to the utility.

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 23 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 24 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 25 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 26 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.1 Line No.: 27 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 28 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 29 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429.1 Line No.: 33 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429.1 Line No.: 34 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues,

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
Southern California Edison Company			
FOOTNOTE DATA			

Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 35 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 36 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 37 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 38 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 39 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 40 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.1 Line No.: 41 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429.2 Line No.: 21 Column:

Directly Charged: All costs associated with services are billed to the utility.

Schedule Page: 429.2 Line No.: 22 Column:

Directly Charged: All costs associated with services are billed to the utility.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 429.2 Line No.: 23 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 24 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 25 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 26 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 27 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 28 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 29 Column:

Directly Charged: All costs associated with services are billed to the utility.
Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.
Number of Employees: This method is based on the total regular or equivalent number of regular employees working for each affiliate.

Schedule Page: 429.2 Line No.: 30 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.
Equity Investment: This allocation method is based on the equity of each affiliate.

Schedule Page: 429.2 Line No.: 35 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Name of Respondent Southern California Edison Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report 2010/Q4
FOOTNOTE DATA			

Schedule Page: 429.2 Line No.: 35 Column:

Edison Enterprise/Source

Schedule Page: 429.2 Line No.: 36 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.2 Line No.: 36 Column:

Edison Enterprise/Source

Schedule Page: 429.2 Line No.: 37 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.2 Line No.: 37 Column:

Edison Enterprise/Source

Schedule Page: 429.2 Line No.: 38 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.2 Line No.: 38 Column:

Edison Enterprise/Source

Schedule Page: 429.2 Line No.: 39 Column:

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.2 Line No.: 39 Column:

Edison Enterprise/Source

Schedule Page: 429.2 Line No.: 40 Column:

Directly Charged: All costs associated with services are billed to the utility.

Multi Factor: This method is based on a formula using each affiliate's proportionate share of: Operating Revenues, Operating Expenses, Total Assets and Number of Employees.

Schedule Page: 429.2 Line No.: 40 Column:

Edison Enterprise/Source

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