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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Southern California Edison Company	**End of** 2018/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/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

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

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

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

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

The CPA Certification Statement should:

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

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

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

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

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.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 1,168 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 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

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

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

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

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year/Period of Report
Southern California Edison Company	End of 2018/Q4

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)*
2244 Walnut Grove Avenue, Rosemead, California 91770

05 Name of Contact Person	06 Title of Contact Person
Aaron D. Moss	VP & Controller

07 Address of Contact Person *(Street, City, State, Zip Code)*
2244 Walnut Grove Avenue, Rosemead, California 91770

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(626) 302-1212	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Aaron D. Moss	Aaron D. Moss	04/17/2019
02 Title		
VP & 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	106b (None)
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)	228a-229a None
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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Mr. Aaron D. Moss, VP 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 electricity, 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) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONTROL OVER RESPONDENT

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

Edison International holds control over respondent by

way of 100% ownership of respondent's common stock.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Bear Creek Uranium Company	Inactive.	-	
2	a Partnership			
3				
4				
5				
6	Edison Material Supply LLC	Non-public utility engaged in	100%	
7	a Delaware Limited Liability Company	providing procurement, inven-		
8		tory and warehousing services		
9				
10	Mono Power Company	Inactive.	100%	
11	a California Company			
12				
13				
14				
15	Southern States Realty (Formerly Southern	Non-public utility engaged	100%	
16	Surplus Realty Co.)	in holding real estate		
17	a California Corporation	interests.		
18				
19	SCE Trust II	Delaware business trust	100%	
20		organized to act as a		
21		financing vehicle.		
22				
23				
24	SCE Trust III	Delaware business trust	100%	
25		organized to act as a		
26		financing vehicle.		
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.

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	SCE Trust IV	Delaware business trust	100%	
2		organized to act as a		
3		financing vehicle.		
4				
5	SCE Trust V	Delaware business trust	100%	
6		organized to act as a		
7		financing vehicle.		
8				
9	SCE Trust VI	Delaware business trust	100%	
10		organized to act as a		
11		financing vehicle.		
12				
13	SCE Trust VII	Delaware business trust	100%	
14		organized to act as a		
15		financing vehicle.		
16				
17	SCE Trust VIII	Delaware business trust	100%	
18		organized to act as a		
19		financing vehicle.		
20				
21				
22				
23				
24				
25				
26				
27				

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

Bear Creek Uranium Company

Mono Power Company, which is 100% owned by the Respondent, owns a 50% partnership interest in the Bear Creek Uranium Company; the remaining interest is owned by Anadarko Petroleum.

Schedule Page: 103 Line No.: 6 Column: d

Edison Material Supply LLC

Respondent is the only member of Edison Material Supply LLC.

Schedule Page: 103 Line No.: 19 Column: d

SCE Trust II

Respondent owns 100% of Common Stock as of 01/29/2013.

Schedule Page: 103 Line No.: 24 Column: d

SCE Trust III

Respondent owns 100% of Common Stock as of 03/06/2014.

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

SCE Trust IV

Respondent owns 100% of Common Stock as of 8/24/2015.

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

SCE Trust V

Respondent owns 100% of Common Stock as of 3/08/2016.

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

SCE Trust VI

Respondent owns 100% of Common Stock as of 6/27/2017.

Schedule Page: 103.1 Line No.: 13 Column: d

SCE Trust VII

Respondent is the depositor.

Schedule Page: 103.1 Line No.: 17 Column: d

SCE Trust VIII

Respondent is the depositor.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chief Executive Officer	Kevin M. Payne	625,931
2			
3			
4	President	Ronald O. Nichols	471,054
5			
6			
7	Senior Vice President and Chief Financial Officer	William M. Petmecky III	536,407
8			
9			
10	Senior Vice President	Phillip R. Herrington	569,743
11			
12			
13	Senior Vice President & General Counsel	Russell C. Swartz	616,152
14			
15			
16			
17	For each "executive officer" listed above, the amount		
18	set forth in column (c), "Salary for Year," is the sum		
19	of the amounts reported pursuant to Item 402 of		
20	Regulation S-K "Salary," "Bonus," "Non-Equity		
21	Incentive Plan Compensation" and "All Other		
22	Compensation" in the Summary Compensation Table		
23	of the Company's Proxy Statement filed with the		
24	Securities and Exchange Commission ("Proxy		
25	Statement"). For additional information required by		
26	Regulation S-K, Item 402, please see the Company's		
27	Proxy Statement. The officers listed above are the		
28	Company's "Named Executive Officers" for purposes of		
29	the Company's 2019 Proxy Statement who fall within the		
30	term "executive officer" above.		
31			
32			
33			
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44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Jeanne Beliveau-Dunn (1)	2244 Walnut Grove Avenue
2		Rosemead, California 91770
3		
4		
5	Michael C. Camuñez	2244 Walnut Grove Avenue
6		Rosemead, California 91770
7		
8		
9	Vanessa C.L. Chang	2244 Walnut Grove Avenue
10		Rosemead, California 91770
11		
12		
13	James T. Morris	2244 Walnut Grove Avenue
14		Rosemead, California 91770
15		
16		
17	Timothy T. O'Toole	2244 Walnut Grove Avenue
18		Rosemead, California 91770
19		
20		
21	Kevin M. Payne	2244 Walnut Grove Avenue
22	Chief Executive Officer	Rosemead, California 91770
23		
24		
25	Pedro J. Pizarro	2244 Walnut Grove Avenue
26		Rosemead, California 91770
27		
28		
29	Louis Hernandez, Jr. (2)	2244 Walnut Grove Avenue
30		Rosemead, California 91770
31		
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33	Linda G. Stuntz	2244 Walnut Grove Avenue
34		Rosemead, California 91770
35		
36		
37	William P. Sullivan	2244 Walnut Grove Avenue
38		Rosemead, California 91770
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41	Ellen O. Tauscher	2244 Walnut Grove Avenue
42		Rosemead, California 91770
43		
44		
45	Peter J. Taylor	2244 Walnut Grove Avenue
46		Rosemead, California 91770
47		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Keith Trent (3)	2244 Walnut Grove Avenue
2		Rosemead, California 91770
3		
4		
5	Brett White	2244 Walnut Grove Avenue
6		Rosemead, California 91770
7		
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9	Please note: The respondent does not have a Board	
10	Executive Committee.	
11		
12		
13	(1) Ms. Beliveau-Dunn was elected to the Board of	
14	Directors on February 28, 2019; effective	
15	February 28, 2019.	
16		
17	(2) Mr. Hernandez resigned from The Board of Directors	
18	on February 27, 2018.	
19		
20	(3) Mr. Trent was elected to The Board of Directors	
21	on October 25, 2018; effective October 25, 2018.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff, Volume No. 6	(TRBAA) ER18-154, ER17-250, ER16-175, ER15-259,
2	FERC Electric Tariff, Volume No. 6	(RSBAA) ER18-184, ER17-232, ER16-176, ER15-216,
3	FERC Electric Tariff, Volume No. 6	(TACBAA) ER18-1207, ER17-1345, ER16-1272,
4	FERC Electric Tariff, Volume No. 6	(Base TRR) ER18-169, ER17-914, ER16-2433,
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Schedule Page: 106 Line No.: 1 Column: b

FERC Electric Tariff, Volume No. 6: ER06-788, ER03-338, ER97-2355

Schedule Page: 106 Line No.: 2 Column: b

FERC Electric Tariff, Volume No. 6: ER05-763, ER04-1209, ER04-890, ER03-142, ER01-315

Schedule Page: 106 Line No.: 3 Column: b

FERC Electric Tariff, Volume No. 6: ER15-1399, ER14-1604, ER13-1174, ER11-3248, ER05-506, ER03-338, ER01-832

Schedule Page: 106 Line No.: 4 Column: b

FERC Electric Tariff, Volume No. 6: ER16-1393, ER16-1292, ER16-686, ER15-1449, ER14-2788, ER13-1253, ER13-1190, ER11-3697

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20171024-5157	10/24/2017	ER18-154	2018 TRBAA UPDATE	FERC Electric Tariff Vol No. 6
2	20171031-5015	10/31/2017	ER18-184	2018 RSBAA UPDATE	FERC Electric Tariff Vol No. 6
3	20170330-5140	03/30/2017	ER17-1345	2017 TACBAA UPDATE	FERC Electric Tariff Vol No. 6
4	20180328-5213	03/28/2018	ER18-1207	2018 TACBAA UPDATE	FERC Electric Tariff Vol No. 6
5	20171027-5004	10/27/2017	ER18-169	2018 TO2018 SUCCESSOR	FERC Electric Tariff Vol No. 6
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Schedule Page: 1061 Line No.: 5 Column: d

2018 TO2018 Successor Formula Transmission Rate

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1		NONE.		
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

Question 1. Franchises

County of Los Angeles

Franchise Ordinance No. 7062

Extension Agreement No. 2018-0052F

Adopted Nov. 27, 2018

Operational Jan 1, 2019

Payment terms 25 years

Expiration Dec 31, 2043

Question 2. Acquisition of ownership in other companies

Not applicable

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

Purchase or sale of an operation unit or system for 2018

1. D. 17-05-025 – Sale of streetlight facilities to the City of Palmdale
2. A.L. 3632-E - Sale of streetlight facilities to the City of Orange
3. A.L. 3644-E - Sale of streetlight facilities to the City of Tustin
4. A.L. 3637-E - Sale of streetlight facilities to the City of Norwalk
5. A.L. 3645-E - Sale of streetlight facilities to the City of Fountain Valley
6. A.L. 3652-E - Sale of streetlight facilities to the City of Chino Hills
7. A.L. 3703-E - Sale of streetlight facilities to the City of La Puente
8. A.L. 3633-E - Sale of streetlight facilities to the City of West Hollywood
9. A.L. 3651-E - Sale of streetlight facilities to the City of Murrieta
10. A.L. 3686-E - Sale of streetlight facilities to the City of Simi Valley
11. A.L. 3693-E - Sale of streetlight facilities to the City of Highland

Question 4. Important Leaseholds

There were no changes in important leaseholds for the 12 months ended December 31, 2018.

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

There were no major/significant extensions or reduction of SCE's service territory for 12 months ended December 31, 2018.

Question 6. Obligations

Long-Term Debt / Security Issuances

Taxable

SERIES NAME	ISSUE DATE	AMOUNT (MILLIONS)	INTEREST RATE	MATURITY DATE	AUTHORIZING CPUC DECISION
Series 2018A	3/5/2018	$450	2.900%	3/1/2021	No. 03-11-018 dated Nov. 13, 2003, 14-02-021 dated Feb. 27, 2014, and 14-03-005 dated Mar. 13, 2014
Series 2018B	3/5/2018	$400	3.650%	3/1/2028	No. 14-03-005 dated Mar. 13, 2014 and 16-02-018 dated Feb. 25, 2016
Series 2018C	3/5/2018	$400	4.125%	3/1/2048	No. 16-02-018 dated Feb. 25, 2016
Series 2018C (reopener)	6/4/2018	$350	4.125%	3/1/2048	No. 16-02-018 dated Feb. 25, 2016
Series 2018D	6/4/2018	$300	3.400%	6/1/2023	No. 16-02-018 dated Feb. 25, 2016
Series 2018C (reopener)	8/2/2018	$550	4.125%	3/1/2048	No. 16-02-018 dated Feb. 25, 2016 and no. 18-06-008 dated June 27, 2018
Series 2018E	8/2/2018	$300	3.700%	8/1/2025	No. 16-02-018 dated Feb. 25, 2016

Tax-Exempt

No tax-exempt debt security issuances for 12 months ended December 31, 2018

Short-Term Obligations:

The SCE short term debt in the 4th quarter 2018 consisted of commercial paper and a loan against the credit facility. The $300 million loan against the credit facility was outstanding from 11/16/18 through 12/2/18. At 12/31/18 the commercial paper principal balance outstanding was $721.2 million and the unamortized discount on commercial paper was $1.2 million. The commercial paper weighted average rate was 3.25% on the $721.2 million outstanding as of 12/31/18. The commercial paper maturities ranged from 1/2/19 to 3/8/19.

Preferred Security Issuances:

No preferred stock security issuances for 12 months ended December 31, 2018

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

There were no changes to articles of incorporation or amendments to charter for the quarter ending December 31, 2018

Question 8. Wage Scale Changes

Wage Scale Changes for 12 months ended December 31, 2018

1. General increases for UWUA employees was 2.75%, effective January 1, 2018

2. Annual merit increase budget for non-represented and non-executive employees is 3.00%, effective February 19, 2018

3. The new Graded Structure Midpoints moved 1.9% effective January 1, 2018

The CIP Structure MRP's did not move

Question 9. Materially important legal matters.

Thomas Fire Litigation

In December 2017, several wind-driven wildfires impacted portions of SCE's service territory and caused substantial damage to both residential and business properties and service outages for SCE customers. The largest of these fires, known as the Thomas Fire, originated in Ventura County and burned acreage located in both Ventura and Santa Barbara Counties. According to CAL FIRE information, the Thomas Fire burned over 280,000 acres, destroyed an estimated 1,063 structures, damaged an estimated 280 structures and resulted in two fatalities.

As of February 26, 2019, SCE was aware of at least 132 lawsuits, representing approximately 2,100 plaintiffs, related to the Thomas Fire naming SCE as a defendant. Sixty-seven of these lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. At least four of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura, Santa Barbara and Los Angeles Counties allege, among other things, negligence, inverse condemnation, trespass, private nuisance, and violations of the public utilities and health and safety codes. By order of the Chair of the California Judicial Council, the lawsuits have been coordinated in the Los Angeles Superior Court.

Montecito Mudslides Litigation

In January 2018, torrential rains in Santa Barbara County produced mudslides and flooding in Montecito and surrounding areas. According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures, and resulted in at least 21 fatalities, with two additional fatalities presumed.

Fifty-five of the 132 lawsuits mentioned under "Thomas Fire Litigation" above allege that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides, resulting in the plaintiffs' claimed damages. Twenty-one of the 55 Montecito Mudslides lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. In addition to other causes of action, some of the Montecito Mudslides lawsuits also allege personal injury and wrongful death. By order of the Chair of the California Judicial Council, the Thomas Fire and Montecito Mudslides lawsuits have been coordinated in the Los Angeles Superior Court.

Woolsey Fire Litigation

In November 2018, several wind-driven wildfires impacted portions of SCE's service territory and caused substantial damage to both residential and business properties and service outages for SCE customers. The largest of these fires, known as the Woolsey Fire, originated in Ventura County and burned acreage located in both Ventura and Los Angeles Counties. According to CAL FIRE information, the Woolsey Fire burned almost 100,000 acres, destroyed an estimated 1,643 structures, damaged an estimated 364 structures and resulted in three fatalities.

As of February 26, 2019, SCE was aware of at least 26 lawsuits, representing approximately 400 plaintiffs, related to the Woolsey Fire naming SCE as a defendant. Seventeen of these lawsuits also name Edison International as a defendant based on its ownership and alleged control of SCE. At least two of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura and Los Angeles Counties allege, among other things, negligence, inverse condemnation, personal injury, wrongful death, trespass, private nuisance, and violations of the public utilities and health and safety codes. The Woolsey Fire lawsuits have also been recommended for coordination in the Los Angeles Superior Court.

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

In 2018, Director Linda Stuntz was an equity partner at the law firm of Stuntz, Davis & Staffier, P.C. ("SD&S"), which paid the Company approximately $141,000 in 2018 to sublease office space in Washington, D.C. The Company's sublease of office space to SD&S began before Ms. Stuntz joined the Board. Ms. Stuntz retired from SD&S effective December 31, 2018 and is no longer affiliated with the firm.

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. 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.

Not applicable

Question 13.

a) Changes in officers and directors of the respondent.

Changes in officers of the respondent since January 1, 2018, are reflected below.

Officer Name	Title	Date First Elected	Effective Date	End Date (if applicable)
Jill C. Anderson	Vice President	12/07/2017	01/22/2018	N/A
Jacqueline Trapp	Senior Vice President	02/22/2018	02/22/2018	N/A
Lisa D. Cagnolatti	Vice President	10/03/2007	11/01/2007	03/01/2018
Albert Ma	Vice President	04/26/2018	05/14/2018	N/A
Steven D. Powell	Senior Vice President	08/23/2018	08/27/2018	N/A
Stuart R. Hemphill	Senior Vice President	06/18/2009	07/01/2009	09/30/2018
Erik T. Takayesu	Vice President	10/25/2018	11/05/2018	N/A
Nestor Martinez	Vice President	10/23/2014	10/23/2014	11/30/2018
Gaddi H. Vasquez	Senior Vice President	04/25/2013	04/25/2013	02/28/2019
Janet T. Clayton	Senior Vice President	04/25/2013	04/25/2013	01/01/2019

Changes in directors of the respondent since January 1, 2018, are reflected below.

Director Name	Date First Elected	Effective Date	End Date (if applicable)
Louis Hernandez, Jr.	08/25/2016	08/25/2016	2/27/2018
Keith Trent	10/25/2018	10/25/2018	N/A
Jeanne Beliveau-Dunn	02/28/2019	02/28/2019	N/A

b) Changes in majority security holders.

There were no changes in majority security holders for the 12 months ended December 31, 2018.

c) Changes in voting powers of the respondent.

There were no changes in voting powers of the respondent for the 12 months ended December 31, 2018.

Question 14. Cash Management Program

There was no cash management program for the quarter ending December 31, 2018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	48,328,134,021	46,270,661,828
3	Construction Work in Progress (107)	200-201	3,882,962,828	3,174,882,248
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		52,211,096,849	49,445,544,076
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	13,841,299,847	13,602,215,051
6	Net Utility Plant (Enter Total of line 4 less 5)		38,369,797,002	35,843,329,025
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	60,920,311	56,310,370
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		171,052,200	173,835,318
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	101,239,448	103,525,880
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		130,733,063	126,619,808
14	Net Utility Plant (Enter Total of lines 6 and 13)		38,500,530,065	35,969,948,833
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		151,593,770	173,343,885
19	(Less) Accum. Prov. for Depr. and Amort. (122)		77,083,574	96,893,058
20	Investments in Associated Companies (123)		50,000	50,000
21	Investment in Subsidiary Companies (123.1)	224-225	145,242	145,869
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	3,975,182	4,538,097
24	Other Investments (124)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		4,333,282,406	4,510,271,869
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		1,748,217	4,358,879
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,413,711,243	4,595,815,541
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		19,587,585	31,410,630
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		81,875	84,875
38	Temporary Cash Investments (136)		22,425,481	504,084,166
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		588,951,537	609,511,281
41	Other Accounts Receivable (143)		507,716,222	471,578,822
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		51,144,487	53,275,712
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		157,971	475,577
45	Fuel Stock (151)	227	2,683,058	3,662,961
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	279,666,024	238,006,741
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	14,648,319	12,736,560

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		3,975,182	4,538,097
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)		144,353,946	227,852,643
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		485,157	239,926
60	Rents Receivable (172)		5,985,690	6,713,818
61	Accrued Utility Revenues (173)		481,805,998	212,084,998
62	Miscellaneous Current and Accrued Assets (174)		9,398,516	9,792,539
63	Derivative Instrument Assets (175)		172,758,591	109,792,923
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,748,217	4,358,879
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)		2,193,838,084	2,375,855,772
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		101,060,561	84,210,666
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	669,504	69,834,552
72	Other Regulatory Assets (182.3)	232	6,705,995,788	5,516,540,735
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,492,148	2,599,464
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	135,362
77	Temporary Facilities (185)		74,538	74,538
78	Miscellaneous Deferred Debits (186)	233	101,438,949	93,603,015
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)		153,217,434	167,812,285
82	Accumulated Deferred Income Taxes (190)	234	2,270,325,118	1,711,569,477
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		9,335,274,040	7,646,380,094
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		54,443,353,432	50,588,000,240

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	end of 2018/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	2,168,054,319	2,168,054,319
3	Preferred Stock Issued (204)	250-251	2,245,054,950	2,245,054,950
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	732,727,600	722,820,759
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	583	583
10	(Less) Capital Stock Expense (214)	254b	53,195,017	53,195,017
11	Retained Earnings (215, 215.1, 216)	118-119	8,717,427,790	9,609,389,281
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-2,604,107	-2,603,481
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)	-22,574,194	-18,721,643
16	Total Proprietary Capital (lines 2 through 15)		13,785,814,466	14,671,722,293
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	12,801,900,000	10,717,971,429
19	(Less) Reaquired Bonds (222)	256-257	0	30,000,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	306,490,453	306,557,633
22	Unamortized Premium on Long-Term Debt (225)		20,878,714	21,617,712
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		64,907,994	32,677,760
24	Total Long-Term Debt (lines 18 through 23)		13,064,361,173	10,983,469,014
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		43,110,642	46,470,069
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		2,771,957,879	162,688,365
29	Accumulated Provision for Pensions and Benefits (228.3)		433,000,391	482,994,414
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		3,030,535,854	2,892,285,940
35	Total Other Noncurrent Liabilities (lines 26 through 34)		6,278,604,766	3,584,438,788
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		719,968,054	1,238,012,199
38	Accounts Payable (232)		1,481,308,801	1,473,712,139
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		19,691,628	27,783,650
41	Customer Deposits (235)		298,815,520	280,781,892
42	Taxes Accrued (236)	262-263	22,208,842	51,800,061
43	Interest Accrued (237)		212,389,942	185,466,253
44	Dividends Declared (238)		13,378,635	225,825,061
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	end of 2018/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		21,940,863	23,031,656
48	Miscellaneous Current and Accrued Liabilities (242)		693,433,208	670,340,513
49	Obligations Under Capital Leases-Current (243)		3,330,460	3,236,017
50	Derivative Instrument Liabilities (244)		6,075,282	1,191,081
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		3,492,541,235	4,181,180,522
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		175,393,317	172,964,405
57	Accumulated Deferred Investment Tax Credits (255)	266-267	71,324,122	81,727,067
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	2,042,294,997	2,233,659,159
60	Other Regulatory Liabilities (254)	278	7,342,217,160	7,045,828,280
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)		7,415,281,021	6,880,852,503
64	Accum. Deferred Income Taxes-Other (283)		775,521,175	752,158,209
65	Total Deferred Credits (lines 56 through 64)		17,822,031,792	17,167,189,623
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		54,443,353,432	50,588,000,240

Schedule Page: 112   Line No.: 28   Column: c

For FERC reporting purposes, the $4.7 billion of liabilities for wildfire-related claims are presented net of $2 billion of insurance receivables (FERC account 228.2). $1 billion of that receivable is due from an associated (affiliated) company. For GAAP reporting purpose, insurance receivables are reflected as an asset.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

STATEMENT OF INCOME

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

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	12,802,630,536	12,368,081,494		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	10,268,126,864	7,027,565,218		
5	Maintenance Expenses (402)	320-323	446,742,857	478,485,451		
6	Depreciation Expense (403)	336-337	1,647,295,589	1,562,525,494		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	213,175,331	244,141,490		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		18,682	218,152,954		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		11,073,760,694	9,915,439,585		
13	(Less) Regulatory Credits (407.4)		10,866,381,877	9,716,307,410		
14	Taxes Other Than Income Taxes (408.1)	262-263	389,151,322	368,985,973		
15	Income Taxes - Federal (409.1)	262-263	-48,867,606	161,726,421		
16	- Other (409.1)	262-263	-27,024,115	34,668,176		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,865,414,010	3,794,803,283		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	2,436,920,859	3,469,822,560		
19	Investment Tax Credit Adj. - Net (411.4)	266	-10,402,945	-6,438,859		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		8	59		
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)		12,514,087,939	10,613,925,157		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		288,542,597	1,754,156,337		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
12,796,966,537	12,362,621,628	2,341,789	2,285,119	3,322,210	3,174,747	2
						3
10,263,935,657	7,024,458,089	1,624,134	1,549,510	2,567,073	1,557,619	4
445,200,259	475,690,599	382,414	420,260	1,160,184	2,374,592	5
1,645,968,668	1,561,450,662	264,497	204,615	1,062,424	870,217	6
						7
213,175,331	244,141,490					8
						9
18,682	218,152,954					10
						11
11,073,760,694	9,915,439,585					12
10,866,340,905	9,716,307,410	40,972				13
388,979,128	368,805,001	58,476	60,984	113,718	119,988	14
-47,671,179	161,726,421	-39,787		-1,156,640		15
-26,719,511	34,788,966	-17,127	-4,445	-287,477	-116,345	16
1,863,271,692	3,793,024,199	212,566	402,948	1,929,752	1,376,136	17
2,435,772,881	3,466,904,565	161,980	344,485	985,998	2,573,510	18
-10,402,945	-6,438,859					19
						20
						21
8	59					22
						23
						24
12,507,402,682	10,608,027,073	2,282,221	2,289,387	4,403,036	3,608,697	25
289,563,855	1,754,594,555	59,568	-4,268	-1,080,826	-433,950	26

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		288,542,597	1,754,156,337		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		62,995,589	65,410,459		
34	(Less) Expenses of Nonutility Operations (417.1)		40,965,246	42,386,658		
35	Nonoperating Rental Income (418)		913,337	1,372,754		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-626	-45		
37	Interest and Dividend Income (419)		57,329,984	7,168,954		
38	Allowance for Other Funds Used During Construction (419.1)		103,788,788	86,934,206		
39	Miscellaneous Nonoperating Income (421)		2,376,746	29,873,224		
40	Gain on Disposition of Property (421.1)		7,492,289	8,065,793		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		193,930,861	156,438,687		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		37,083	312,720		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		20,004,816	23,481,022		
46	Life Insurance (426.2)		-35,767,137	-34,233,934		
47	Penalties (426.3)		-3,071,497	5,846,962		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		23,566,748	10,592,380		
49	Other Deductions (426.5)		-4,423,624	721,339,797		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		346,389	727,338,947		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,318,261	2,846,890		
53	Income Taxes-Federal (409.2)	262-263	-4,181,002	-387,435,085		
54	Income Taxes-Other (409.2)	262-263	-1,154,321	-134,277,396		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	23,236,776	195,649,057		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	21,917,339	223,748,428		
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)		-697,625	-546,964,962		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		194,282,097	-23,935,298		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		549,367,056	488,235,571		
63	Amort. of Debt Disc. and Expense (428)		11,795,239	10,026,888		
64	Amortization of Loss on Reaquired Debt (428.1)		14,594,851	16,710,267		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		140,670,504	106,821,086		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		44,227,371	27,669,237		
70	Net Interest Charges (Total of lines 62 thru 69)		672,200,279	594,124,575		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		-189,375,585	1,136,096,464		
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)		-189,375,585	1,136,096,464		

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		9,420,413,251	9,250,439,192
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Cumulative Effect of Accounting Change ASU 2016-01		4,600,552	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		4,600,552	
10				
11	Stock-Based Compensation		-10,260,490	(37,900,632)
12	Capital Stock Expense Write-Off			(15,401,698)
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-10,260,490	(53,302,330)
16	Balance Transferred from Income (Account 433 less Account 418.1)		-189,374,959	1,136,096,509
17	Appropriations of Retained Earnings (Acct. 436)			
18	Appropriations of Retained Earnings	215.1	-2,636,312	(3,722,448)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-2,636,312	(3,722,448)
23	Dividends Declared-Preferred Stock (Account 437)			
24	Preferred and Preference Stock Dividends (See Footnote)		-120,926,594	(124,097,672)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-120,926,594	(124,097,672)
30	Dividends Declared-Common Stock (Account 438)			
31	Common Stock Dividends		-576,000,000	(785,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-576,000,000	(785,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,525,815,448	9,420,413,251
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		191,612,342	188,976,030
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		191,612,342	188,976,030
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		8,717,427,790	9,609,389,281
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-2,603,481	(2,603,436)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-626	(45)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-2,604,107	(2,603,481)

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

SCE received approval from FERC (docket AC19-20) for authorization to use account 439 to record the cumulative effect adjustment to retained earnings for SCE’s adoption of the ASU 2016-01 “Recognition and Measurement of Financial Assets and Financial Liabilities". For further information, see the Notes to the financial statements included on page 122-123.

Schedule Page: 118   Line No.: 24   Column: a

NOTES TO STATEMENT OF RETAINED EARNINGS FOR THE
YEAR TO DATE DECEMBER 31, 2018

		Dividend
Preferred Stock -		
4.08% Series	$	1,272,000
4.24% Series		1,785,703
4.32% Series		663,000
4.78% Series		1,549,641
Preference Stock -		
6.250% Series E		21,875,000
6.250% Series F		
5.100% Series G		20,400,000
5.750% Series H		15,812,500
5.375% Series J		17,468,750
5.450% Series K		16,350,000
5.000% Series L		23,750,000
Total Dividends	$	120,926,594

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)	-189,375,585	1,136,096,464
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,860,489,602	2,024,819,938
5	Amort. of Nuc. Fuel, Loss on Reacq. Debt, Prem. & Disc. of L/T Debt	65,444,231	69,229,873
6			
7			
8	Deferred Income Taxes (Net)	-574,509,922	296,881,352
9	Investment Tax Credit Adjustment (Net)	-6,080,435	-6,438,859
10	Net (Increase) Decrease in Receivables	-45,112,182	4,682,865
11	Net (Increase) Decrease in Inventory	-49,537,283	-11,593,359
12	Net (Increase) Decrease in Allowances Inventory	-2,474,674	21,313,195
13	Net Increase (Decrease) in Payables and Accrued Expenses	29,023,841	66,252,853
14	Net (Increase) Decrease in Other Regulatory Assets	-700,863,120	-389,169,840
15	Net Increase (Decrease) in Other Regulatory Liabilities	607,302,116	393,075,442
16	(Less) Allowance for Other Funds Used During Construction	103,788,788	86,934,206
17	(Less) Undistributed Earnings from Subsidiary Companies	-626	-45
18	Other (provide details in footnote):		
19	Prepaid and Accrued Taxes	-84,387,766	-282,420,913
20	Nuclear Decommissioning Trusts	-109,176,550	-196,725,002
21	Other-Net	2,493,323,090	696,248,665
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	3,190,277,201	3,735,318,513
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-3,926,022,280	-3,270,039,128
27	Gross Additions to Nuclear Fuel	-39,902,411	-38,430,866
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-6,524,949	-10,205,594
30	(Less) Allowance for Other Funds Used During Construction	-103,788,788	-86,934,206
31	Other (provide details in footnote):		
32	Cost of Removal, Salvage Value and Others	-622,134,733	-524,391,082
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-4,490,795,585	-3,756,132,464
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	39,677,265	25,096,900
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
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	4,340,052,357	5,238,622,885
54	Purchases of Nuclear Decommissioning Trust Investments	-4,231,377,216	-5,041,938,980
55	Other Investments	42,328,294	31,404,736
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-4,300,114,885	-3,502,946,923
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	2,715,070,500	1,456,359,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Preference Stock Issued		475,000,000
66	Net Increase in Short-Term Debt (c)		468,502,637
67	Other (provide details in footnote):		
68			
69	Proceeds from Stock Option Exercises	11,859,397	48,010,075
70	Cash Provided by Outside Sources (Total 61 thru 69)	2,726,929,897	2,447,871,712
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-639,403,593	-881,715,620
74	Preferred Stock		-475,000,000
75	Common Stock		
76	Other: Long-Term Debt Issuance Cost and Other	-19,965,882	-65,164,421
77	Shares Purchased for Stock-Based Compensation	-22,100,606	-85,910,707
78	Net Decrease in Short-Term Debt (c)	-519,733,841	
79	Dividends on Preference Stock	-115,656,253	-118,884,934
80	Dividends on Preferred Stock	-5,716,768	-4,823,916
81	Dividends on Common Stock	-788,000,000	-573,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	616,352,954	243,372,114
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-493,484,730	475,743,704
87			
88	Cash and Cash Equivalents at Beginning of Period	535,579,671	59,835,967
89			
90	Cash and Cash Equivalents at End of period	42,094,941	535,579,671

Schedule Page: 120 Line No.: 10 Column: c

Revised to reflect the adoption of ASU 2016-15

Schedule Page: 120 Line No.: 13 Column: c

Revised to reflect the adoption of ASU 2016-15

Schedule Page: 120 Line No.: 21 Column: b

Includes wildfire insurance claims, net of insurance receivable of $2.7 billion.

Schedule Page: 120 Line No.: 21 Column: c

Revised to reflect the adoption of ASU 2016-15

Schedule Page: 120 Line No.: 26 Column: c

Revised to reflect the adoption of ASU 2016-15

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

Revised to reflect the adoption of ASU 2016-15

NOTES TO FINANCIAL STATEMENTS

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

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

GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

2017/2018 Wildfire/Mudslide Events	the Thomas Fire, the Montecito Mudslides and the Woolsey Fire, collectively
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
ARO	asset retirement obligation
Bcf	billion cubic feet
bonus depreciation	Federal tax deduction of a percentage of the qualifying property placed in service during periods permitted under tax laws
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
CPUC	California Public Utilities Commission
DOE	U.S. Department of Energy
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	generally accepted accounting principles
GRC	general rate case
GWh	gigawatt-hours
IRS	Internal Revenue Service
MHI	Mitsubishi Heavy Industries, Inc. and related companies
Montecito Mudslides	mudslides and flooding in Montecito, Santa Barbara County, that occurred in January 2018
MW	megawatts
NEIL	Nuclear Electric Insurance Limited
OII	Order Instituting Investigation
OII Parties	SCE, SDG&E, The Alliance for Nuclear Responsibility, The California Large Energy Consumers Association, California State University, Citizens Oversight dba Coalition to Decommission San Onofre, the Coalition of California Utility Employees, the Direct Access Customer Coalition, Ruth Henricks, PAO, TURN, and Women's Energy Matters, all of whom are parties to the Revised San Onofre Settlement Agreement
Palo Verde	nuclear electric generating facility located near Phoenix, Arizona in which SCE holds a 15.8% ownership interest
PAO	CPUC's Public Advocates Office (formerly known as the Office of Ratepayer Advocates or ORA)
PBOP(s)	postretirement benefits other than pension(s)
PG&E	Pacific Gas & Electric Company
Prior San Onofre Settlement Agreement	San Onofre OII Settlement Agreement by and among TURN, PAO, SDG&E, the Coalition of California Utility Employees, and Friends of the Earth, dated November 20, 2014
Revised San Onofre Settlement Agreement	Revised San Onofre OII Settlement Agreement among OII Parties, dated January 30, 2018 and modified on August 2, 2018
ROE	return on common equity

San Onofre	retired nuclear generating facility located in south San Clemente, California in which SCE holds a 78.21% ownership interest
SCE	Southern California Edison Company, a wholly-owned subsidiary of Edison International
SDG&E	San Diego Gas & Electric
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC
Tax Reform	Tax Cuts and Jobs Act signed into law on December 22, 2017
Thomas Fire	a wind-driven fire that originated in Ventura County in December 2017
TURN	The Utility Reform Network
VCFD	Ventura County Fire Department
Woolsey Fire	a wind-driven fire that originated in Ventura County in November 2018

ITEM 1. NOTES TO FINANCIAL STATEMENTS
Summary of Significant Accounting Policies

Organization and Basis of Presentation

SCE is an investor-owned public utility primarily engaged in the business of supplying and delivering electricity to an approximately 50,000 square mile area of southern California. SCE's consolidated financial statements include the accounts of SCE and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the consolidated financial statements.

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 services, 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 a 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.

The financial statements are prepared in accordance with the requirements of the Federal Energy Regulatory Commission ("FERC") as set forth in its applicable Uniform System of Accounts and published releases, which is a comprehensive basis of accounting other than generally accepted accounting principles, require management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures 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 can differ from those estimates.

The notes below are excerpts from SCE's Form 10-K for the year ended December 31, 2018, as filed with the Securities and Exchange Commission ("SEC") on February 28, 2019, and include specific information requested by the FERC. See SCE's Annual Report on Form 10-K filed with the Securities and Exchange Commission for the year ended December 31, 2018 for financial statements and complete footnotes prepared in accordance with accounting principles generally accepted in the United States of America. Subsequent events were evaluated through the date the FERC Form 1 report was filed.

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

- Equity Investment Differences

  SCE accounts for its investments in majority-owned subsidiaries using the equity method (FERC account 123.1) rather than consolidating the assets, liabilities, revenues and expenses of the subsidiaries which is required by GAAP, except for Edison Material Supply LLC. Due to the nature of the business, SCE consolidates Edison Material Supply LLC. In general, the accounting for investments in majority-owned subsidiaries using the equity method rather than the method in accordance with GAAP has no effect on net income or retained earnings.

- Asset Retirement Obligation ("ARO")

  The accumulated net removal costs for SCE's regulated plant assets that do not meet the definition of an ARO or conditional ARO under authoritative accounting guidance are classified as regulatory liabilities under GAAP and as accumulated depreciation under FERC (FERC account 108 and 119).

- 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 (FERC account 128), a noncurrent asset. For GAAP reporting purposes, this asset is classified as a miscellaneous deferred debit, which is also a noncurrent asset. In addition, for FERC reporting purposes, all components of net periodic benefit costs are recorded as operation expenses (FERC account 926). FERC has also allowed entities to capitalize all components of net periodic benefit costs, however, SCE elected to limit the capitalization of net periodic benefit costs to the service cost component. GAAP presents service costs as operating expense and non-service costs within other income and expenses, and limits the capitalization of benefit costs to the service cost component. See "New Accounting Guidance" below for further information.

- Debt Issuance Costs

  For FERC reporting purposes, debt issuance costs are classified as unamortized debt expense and reflected as an asset (FERC account 181) on the FERC balance sheet. For GAAP reporting purposes, long-term debt issuance costs are classified as a reduction of the debt balance.

- Liabilities for wildfire-related claims

  For FERC reporting purposes, liabilities for wildfire-related claims are presented net of insurance receivables (FERC account 228.2). For GAAP reporting purposes, insurance receivables are reflected as an asset.

- Other Differences

  The FERC required current maturities of long-term debt to be included as part of long-term debt (FERC account 221), while GAAP requires such maturities to be classified as a current liability. Regulatory assets and liabilities are classified as current and noncurrent for GAAP, while FERC classifies all regulatory assets (FERC accounts 182.2 and 182.3) and liabilities (FERC account 254) as noncurrent. Retained earnings are presented differently under the Uniform System of Accounts for FERC purposes than it is for GAAP purposes.

Effective January 1, 2018, SCE adopted several accounting standards retrospectively. Prior year financial statements have been reclassified and updated to reflect the retrospective application of these standards as applicable. For further information, see "New Accounting Guidance" below.

During the second quarter of 2018, SCE determined that certain tax expenses were improperly allocated between utility and non-utility operations in the 2017 FERC Form 1 statement of income; $257 million was recorded in FERC account 409.1 and should have been recorded in 409.2. This misclassification had no impact on total income tax expense, total net income, or the FERC formula rate. Based on qualitative and quantitative factors, SCE concluded that the error was not material to the previously filed financial statements and therefore previously reported amounts have not been adjusted.

Cash and Cash Equivalents

Cash equivalents consist of cash and short-term, highly liquid investments. Cash equivalents are stated at fair value. Cash is temporarily invested until required for check clearing. Checks issued, but not yet paid by the financial institution, are reclassified from cash to accounts payable were $65 million and $63 million at December 31, 2018 and 2017, respectively.

Allowance for Uncollectible Accounts

Allowances for uncollectible accounts are provided based upon a variety of factors, including historical amounts written-off, current economic conditions and assessment of customer collectability.

Inventory

SCE's inventory is primarily composed of materials, supplies and spare parts, and generally stated at average cost.

Emission Allowances and Energy Credits

SCE is allocated greenhouse gas ("GHG") allowances annually which it is then required to sell into quarterly auctions. GHG proceeds from the auctions are recorded as a regulatory liability to be refunded to customers. SCE purchases GHG allowances in quarterly auctions or from counterparties to satisfy its GHG compliance obligations and recovers such costs of GHG allowances from customers. GHG allowances held for use are stated, similar to an inventory method, at the lower of weighted-average cost or market.

SCE is allocated low carbon fuel standard credits which it sells to market participants. Proceeds from the sales, net of program costs, are recorded in a balancing account to be refunded to eligible customers.

Property, Plant and Equipment

SCE plant additions, including replacements and betterments, are capitalized. Direct material and labor and indirect costs such as construction overhead, administrative and general costs, pension and benefits, and property taxes are capitalized as part of plant additions. The California Public Utilities Commission (“CPUC”) authorizes a capitalization rate for each of the indirect costs which are allocated to each project based on either labor or total costs. In addition, allowance for funds used during construction (“AFUDC”) is capitalized by SCE for certain projects.

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 $104 million, $87 million and $74 million in 2018, 2017 and 2016, respectively. AFUDC debt was $44 million, $28 million and $23 million in 2018, 2017 and 2016, respectively.

Under the San Onofre OII Settlement Agreement, the unamortized portion of SCE's investment other than nuclear fuel may, at SCE's option, be excluded from SCE's capital structure for purposes of determining regulatory capital requirements and to allow SCE to finance those assets solely with debt. The terms of the San Onofre OII Settlement Agreement provide that if SCE selects the debt financing option and finances these regulatory assets at a cost lower than the return authorized by the San Onofre OII Settlement Agreement, the savings will be shared equally between customers and SCE. In January 2015, SCE issued $550 million of 1.845% amortizing first and refunding mortgage bonds due in 2022 and $325 million of 2.40% first and refunding mortgage bonds due in 2022. These bonds have been designated as a financing of the San Onofre regulatory asset and were excluded from the AFUDC rate calculation as they are not a source of funds for construction financing. FERC rules prescribe long-term debt used in the AFUDC rate calculation to be based upon values as of the end of the preceding year. At December 31, 2016, SCE had long-term debt of $757 million and a regulatory asset of $684 million related to San Onofre, the lesser of which was excluded from the AFUDC rate calculation during 2017. In accordance with the Revised San Onofre Settlement Agreement, SCE wrote down the San Onofre regulatory asset during the fourth quarter of 2017, which discontinued the exclusion of associated debt from the AFUDC rate calculation, effective January 2018. See Item 2 below for a discussion of the Revised Settlement Agreement.

In 2007, FERC issued an order granting ROE incentive adders, recovery of the ROE and incentive adders during the construction phase (referred to CWIP) and recovery of abandoned plant costs for many of SCE’s transmission projects. In addition, the FERC granted an incentive for California Independent System Operator ("CAISO") participation. The order permits SCE to include 100% of prudently-incurred capital expenditures in rate base during construction of the projects and earn a return on equity, rather than capitalizing AFUDC.

If SCE had not implemented this transmission incentive mechanism, and continued to follow FERC Uniform System of Accounts for these projects, approximately $462 million and $444 million would have been capitalized as of December 31, 2018 and 2017, respectively. The following is a partial balance sheet that includes the amounts not capitalized because of the transmission rate incentives.

(in millions)	December 31, 2018	December 31, 2017
Utility property, plant and equipment	$ 48,737	$ 46,679
Construction work in progress	3,936	3,210
Total utility property plant and equipment	52,673	49,889
(Less) accumulated provision for depreciation, amortization and depletion	(13,888)	(13,639)
Net utility property, plant and equipment	$ 38,785	$ 36,250

Estimated useful lives (authorized by the CPUC in the 2015 general rate case ("GRC) and weighted-average useful lives of SCE's property, plant and equipment, are as follows:

	Estimated Useful Lives	Weighted-Average Useful Lives
Generation plant	10 years to 54 years	37 years
Distribution plant	20 years to 60 years	43 years
Transmission plant	40 years to 65 years	52 years
General plant and other	5 years to 60 years	22 years

Depreciation of utility property, plant and equipment is computed on a straight-line, remaining-life basis. SCE's depreciation expense was $1.65 billion, $1.61 billion and $1.52 billion for 2018, 2017 and 2016, respectively. Depreciation expense stated as a percent of average original cost of depreciable utility plant was, on a composite basis, 3.7%, 3.8% and 3.8% for 2018, 2017 and 2016, respectively. The original costs of retired property is charged to accumulated depreciation.

Nuclear fuel for the Palo Verde Nuclear Generating Station ("Palo Verde") 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. Palo Verde nuclear fuel is amortized using the units of production method.

Major Maintenance

Major maintenance costs for SCE's power plant facilities and equipment are expensed as incurred.

Energy Storage Assets

At December 31, 2018, SCE's energy storage assets totaled $54 million. The following table summarizes the operations associated with these energy storage assets for the year ended December 31, 2018:

Name of the Energy Storage Project	Mira Loma Unit A	Mira Loma Unit B	Center Peaker[6]	Grapeland Peaker[6]	Total[7]
Functional Classification	Production	Production	Production	Production	
Location of the Project	Ontario, CA	Ontario, CA	Norwalk, CA	Rancho Cucamonga, CA	
MWHs[1]	7,948	6,573	694	769	15,984
MWHs Delivered to the Grid to Support[2]:	6,869	5,626	529	478	13,502
MWHs Lost During Conversion, Storage an Discharge of Energy[2]:	1,059	924	165	290	2,438
MWHs Sold	4,309	3,896	-	-	8,205
Revenues from Energy Storage Operations:	202,298	139,991	-	-	342,289
Power Purchased for Storage Operations (555.1)[3,7]	50,563	128,751	-	-	179,314
Other Costs Associated with Self-Generated Power[4]	223,985	170,892	81,000	81,000	556,877
Project Costs[2,5]	16,982,580	17,084,067	10,034,487	10,039,539	54,140,673

1 Represents megawatt hours (MWH) purchased, generated, or received in exchange transactions for storage.

2 Relates to production functional use as there were no transmission- or distribution-related energy storage assets at December 31, 2018.

3 Total power purchased for storage operations were recorded in the existing purchased power account 555, which would have been reported in account 555.1.

4 Other costs associated with energy storage plants were recorded in the existing maintenance of generating and electric plant account 553, which would have been reported in account 553.1.

5 The project costs were included in accounts 101 and 106 and were reported in the existing functional plant account 346, which would have been reported in energy storage account 348.

6 Relates to energy storage assets, which are located at sites that have both battery and gas turbine operations. For the year ended December 31, 2018, SCE sold 14,862 MWH and 9,894 MWH and recognized revenue of $1,556,744 and $1,081,136 from the battery and gas turbine operations at the Center Peaker and Grapeland Peaker sites, respectively.

7 The fuel costs for the Center Peaker and Grapeland Peaker were excluded from the table above as the fuel costs for these energy storage

assets are disclosed in the Steam-Electric Generating Plant Statistics Page (See 402-403a, line 20 for details).

Impairment of Long-Lived Assets

Impairments of long-lived assets are evaluated 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. Fair value is determined via market, cost and income based valuation techniques, as appropriate.

Accounting principles for rate-regulated enterprises also require recognition of an impairment loss if it becomes probable that the regulated utility will abandon a plant investment, or if it becomes probable that the cost of a recently completed plant will be disallowed, either directly or indirectly, for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made.

Nuclear Decommissioning and Asset Retirement Obligations

The fair value of a liability for an 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, SCE capitalizes the cost by increasing the carrying amount of the related long-lived asset. For each subsequent period, the liability is increased for accretion expense and the capitalized cost is depreciated over the useful life of the related asset.

AROs related to decommissioning of SCE's nuclear power facilities are based on site-specific studies conducted as part of each Nuclear Decommissioning Cost Triennial Proceeding ("NDCTP") conducted before the CPUC. Revisions of an ARO are established for updated site-specific decommissioning cost estimates.

SCE adjusts its nuclear decommissioning obligation into a nuclear-related ARO regulatory asset and also records an ARO regulatory liability as a result of timing differences between the recognition of costs and the recovery of costs through the ratemaking process.

SCE has not recorded an ARO for assets that are expected to operate indefinitely or where SCE cannot estimate a settlement date (or range of potential settlement dates). As such, ARO liabilities are not recorded for certain retirement activities, including certain hydroelectric facilities.

The following table summarizes the changes in SCE's ARO liability:

	December 31,	
(in millions)	2018	2017
Beginning balance	$ 2,892	$ 2,586
Accretion[1]	169	166
Revisions	110	376
Liabilities settled	(140)	(236)
Ending balance	$ 3,031	$ 2,892

1 An ARO represents the present value of a future obligation. Accretion is an increase in the liability to account for the time value of money resulting from discounting.

The ARO for decommissioning SCE's San Onofre Nuclear Generating Station ("San Onofre") and Palo Verde nuclear power facilities is $2.8 billion as of December 31, 2018. The liability to decommission SCE's nuclear power facilities is based on a 2017 decommissioning study that was filed as part of the 2018 NDTCP for San Onofre Units 1, 2, and 3, with revisions to the cost estimate in 2018 for San Onofre Units 2 and 3 and a 2016 decommissioning study for Palo Verde, with revisions to the cost estimate in 2017. SCE revised the ARO for San Onofre Units 2 and 3 due to increases in decommissioning cost estimates in 2018, related to the impact of operational uncertainties, and in 2017, related to changes to onboarding the general contractor at San Onofre.

The initial activity phase of radiological decommissioning of San Onofre Units 2 and 3 began in June 2013 with SCE filing a certification of permanent cessation of power operations at San Onofre with the Nuclear Regulatory Commission and some spent nuclear fuel was transferred to dry cask storage in the Independent Spent Fuel Storage Installation ("ISFSI") between 2007 and 2012. The transfer of the remaining spent nuclear fuel from Units 2 and 3 to the ISFSI began in 2018. However, the spent fuel transfer operations were suspended on August 3, 2018 due to an incident that occurred when an SCE contractor was loading a spent fuel canister into the ISFSI. The incident did not result in any harm to the public or workers and the canister was subsequently safely loaded into the ISFSI. SCE cannot predict when fuel transfer operations at San Onofre will recommence.

Decommissioning costs, which are recovered through 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 deferred as decreases to the ARO regulatory liability account, resulting in no impact on earnings.

SCE has collected in rates amounts for the future decommissioning of its nuclear assets, and has placed those amounts in independent trusts. Amounts collected in rates in excess of the ARO liability are classified as regulatory liabilities.

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 currently estimates that it will spend approximately $7.2 billion through 2079 to decommission its nuclear facilities. This estimate is based on SCE's decommissioning cost methodology used for ratemaking purposes, escalated at rates ranging from 2.2% to 7.5% (depending on the cost element) annually. These costs are expected to be funded from independent decommissioning trusts. SCE estimates annual after-tax earnings on the decommissioning funds of 2.4% to 3.8%. Future decommissioning costs related to SCE's nuclear assets are expected to be funded from independent decommissioning trusts. If the assumed return on trust assets is not earned or costs escalate at higher rates, SCE expects that additional funds needed for decommissioning will be recoverable through future rates, subject to a reasonableness review. Due to regulatory recovery of SCE's nuclear decommissioning expense, prudently incurred costs for nuclear decommissioning activities do not affect SCE's earnings. SCE's nuclear decommissioning costs are subject to CPUC review through the triennial regulatory proceeding. SCE's nuclear decommissioning trust investments primarily consist of fixed income investments that are classified as available-for-sale and equity investments. Due to regulatory mechanisms, investment earnings and realized gains and losses have no impact on earnings. Unrealized gains and losses on decommissioning trust funds, including other-than-temporary impairment, 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 fixed income 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 carrying value for that security at the time of sale, SCE recognizes a related realized gain or loss, respectively.

Deferred Financing Costs

Debt premium, discount and issuance expenses incurred in connection with obtaining financing are deferred and amortized on a straight-line basis. Under CPUC ratemaking procedures, SCE's 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 $153 million and $168 million at December 31, 2018 and 2017, respectively. SCE had unamortized debt issuance costs related to issuances under the credit facilities of $8 million at December 31, 2018 and $7 million at December 31, 2017, respectively. In addition, SCE had debt issuance costs related to issuances of long-term debt of $93 million and $77 million at December 31, 2018 and December 31, 2017, respectively.

Amortization of deferred financing costs charged to interest expense was $26 million, $27 million and $27 million for 2018, 2017 and 2016, respectively.

Revenue Recognition

Revenue is recognized by SCE when a performance obligation to transfer control of the promised goods is satisfied or when services are rendered to customers. This typically occurs when electricity is delivered to customers, which includes amounts for services rendered but unbilled at the end of a reporting period.

In February 2018, SCE updated its 2018 GRC application, SCE's triennial CPUC-jurisdictional rate setting proceedings, for the impact of Tax Reform resulting in a requested 2018 base rate revenue requirement of $5.534 billion, a decrease of $106 million from the 2017 GRC authorized revenue requirement. SCE also requested base rate revenue requirements of $5.965 billion in 2019 and $6.468 billion in 2020. The CPUC did not issue a decision on the 2018 GRC application during 2018, therefore SCE recognized revenue based on the 2017 authorized revenue requirement, adjusted for items SCE has determined to be probable of occurring, primarily the July 2017 cost of capital decision and Tax Reform. The amounts billed to customers for the year ended December 31, 2018 were based on the 2017 authorized revenue requirement and a regulatory liability has been established to record the associated adjustments.

In April 2019, the CPUC issued a proposed decision, which, if adopted, would result in base rate revenue requirements of $5.102 billion in 2018, $5.422 billion in 2019 and $5.823 billion in 2020 representing a decrease from requested amounts of $433 million, $544 million, and $645 million, respectively. A final decision is expected in the second quarter of 2019 and could result in material changes to the proposed decision. It is SCE's policy to account for regulatory decisions in the period in which they are received. The CPUC has authorized the establishment of a GRC memorandum account, which will make the 2018 and 2019 revenue requirements ultimately adopted by the CPUC retroactive as of January 1, 2018 and January 1, 2019, respectively.

In October 2017, SCE filed a formula rate with the FERC. In December 2017, the FERC issued an order setting the effective date of SCE's new FERC formula rate as of January 1, 2018, subject to settlement procedures and refund. Pending resolution of the FERC formula rate proceeding, SCE is recognizing revenue based on the FERC formula rate adjusted for the impact of Tax Reform and other adjustments.

CPUC and FERC rates decouple authorized revenue from the volume of electricity sales and the price of energy procured so that SCE receives revenue equal to amounts authorized by the relevant regulatory agencies. As a result, the volume of electricity sold to customers and specific customer classes does not have a direct impact on SCE's financial results.

SCE's Revenue from Contracts with Customers

Provision of Electricity

SCE principally generates revenue through supplying and delivering electricity to its customers. Rates charged to customers are based on tariff rates, approved by the CPUC and FERC. Revenue is authorized by the CPUC through triennial GRC proceedings which are intended to provide SCE a reasonable opportunity to recover its costs and earn a return on its CPUC-jurisdictional rate base. The CPUC sets an annual revenue requirement for the base year and the remaining two years are set by a methodology established in the GRC proceeding. As described above, SCE also earns revenue, with no return, to recover costs for power procurement and other activities.

Revenue is authorized by the FERC through a formula rate which is intended to provide SCE a reasonable opportunity to recover transmission capital and operating costs that are prudently incurred, including a return on its FERC-jurisdictional rate base. Under the operation of the formula rate, transmission revenue is updated to actual cost of service annually.

For SCE's electricity sales for non-residential customers, SCE satisfies the performance obligation of delivering electricity over time as the customers simultaneously receive and consume the delivered electricity.

Energy sales are typically on a month-to-month implied contract for transmission, distribution and generation services. Revenue is recognized over time as the energy is supplied and delivered to customers and the respective revenue is billed and paid on a monthly basis.

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. SCE's franchise fees billed to customers were $133 million, $133 million and $111 million for the years ended December 31, 2018, 2017 and 2016, respectively. When SCE acts as an agent for sales and use tax, the taxes are accounted for on a net basis. Amounts billed to and collected from customers for these taxes are remitted to the taxing authorities and are not recognized as electric utility revenue.

SCE's Alternative Revenue Programs

The CPUC and FERC have authorized additional, alternative revenue programs which adjusts billings for the effects of broad external factors or compensates SCE for demand-side management initiatives and provides for incentive awards if SCE achieves certain objectives. These alternative revenue programs allow SCE to recover costs that SCE has been authorized to pass on to customers, including costs to purchase electricity and natural gas, and to fund public purpose, demand response, and customer energy efficiency programs. In general, revenue is recognized for these alternative revenue programs at the time the costs are incurred and, for incentive-based programs, at the time the awards are approved by the CPUC. SCE begins recognizing revenues for these programs when a program has been established by an order from either the CPUC or FERC that allows for automatic adjustment of future rates, the amount of revenue for the period is objectively determinable and probable of recovery and the revenue will be collected within 24 months following the end of the annual period.

Power Purchase Agreements

SCE enters into power purchase agreements ("PPAs") in the normal course of business. A power purchase agreement may be considered a variable interest in a variable interest entity ("VIE"). If SCE is the primary beneficiary in the VIE, SCE should consolidate the VIE. None of SCE's PPAs resulted in consolidation of a VIE at December 31, 2018 and 2017.

A PPA may also contain a lease for accounting purposes. See "Leases" below for further discussion of SCE's PPAs, including agreements that are classified as operating and capital leases for accounting purposes.

A PPA that does not contain a lease may be classified as a derivative which is recorded at fair value on the consolidated balance sheets. These PPAs may be eligible for an election to designate as a normal purchase and sale, which is accounted for on an accrual basis as an executory contract. PPAs that do not meet the above classifications are accounted for on an accrual basis.

Derivative Instruments

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.

During the third quarter of 2017, SCE designated certain derivative contracts as normal purchase and normal sale contracts, which resulted in a reclassification of $914 million from derivative liabilities to other liabilities. These liabilities will be amortized over the remaining contract terms.

Realized gains and losses from SCE's 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.

Leases

SCE enters into PPAs that may contain leases, as discussed under "Power Purchase Agreements" above. A PPA contains a lease when SCE purchases substantially all of the output from a specific plant and does not otherwise meet a fixed price per unit of output exception. SCE also enters into a number of agreements to lease property and equipment in the normal course of business, primarily related to vehicles, office space and other equipment. Minimum lease payments under SCE's operating leases for property and equipment are reflected as operation expenses.

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. Generally, Edison International does not issue new common stock for settlement of equity awards, which are recorded as part of retained earnings. Rather, a third party is used to purchase shares from the market and deliver such shares for the settlement of option exercises, performance shares, deferred stock units and restricted stock units. The performance shares awarded that are earned are settled solely in cash. Deferred stock units and 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.

Stock-based compensation expense is recognized on a straight-line basis over the requisite service period and is based on the number of awards that are expected to vest. SCE estimates the number of awards that are expected to vest rather than account for forfeitures when they occur. For awards granted to retirement-eligible participants, stock compensation expenses are recognized on a prorated basis over the initial year. For awards granted to participants who become eligible for retirement during the requisite service period, stock compensation expenses are recognized over the period between the date of grant and the date the participant first becomes eligible for retirement. Under new accounting guidance adopted in 2016, share-based payments may create a permanent difference between the amount of compensation expense recognized for book and tax purposes. The tax impact of this permanent difference is recognized in earnings in the period it is created. Effective January 1, 2016, the excess tax benefits are classified as an operating activity along with other income tax cash flows on the statement of cash flows.

Income Taxes

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 in the consolidated balance sheets. In December 2017, the Tax Cuts and Jobs Act ("Tax Reform") was signed into law. This comprehensive reform of tax law reduces the federal corporate income tax rate from 35% to 21% which resulted in the re-measurement of deferred taxes using the new tax rate. Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are deferred and amortized to income tax expense over the lives of the properties or the term of the power purchase agreement of the respective project.

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.

On November 15, 2018, the FERC issued a policy statement, Docket No. PL19-2-000, requiring companies to disclose the accounting and ratemaking treatment of excess and deficient accumulated deferred income taxes (ADIT) in light of the U.S. federal corporate income tax rate change from 35% to 21%, as enacted by Tax Reform. See "Income tax - Tax Reform" below for further details.

New Accounting Guidance

Accounting Guidance Adopted

In May 2014, the Financial Accounting Standards Board ("FASB") issued an accounting standards update on revenue recognition and further amended the standard in 2016 and 2017. Under the new standard, revenue is recognized when a good or service is transferred to the customer and the customer obtains control of the good or service. Some revenue arrangements, such as alternative revenue programs which include balancing account overcollections and undercollections, are excluded from the scope of the new standard and, therefore, will be accounted for and presented separately from revenue recognized from contracts with customers in the disclosures. SCE adopted this standard effective January 1, 2018, using the modified retrospective method for contracts that were not completed as of the adoption date.

In January 2016, the FASB issued an accounting standards update that amends the guidance on the classification and measurement of financial instruments, and further amended the guidance in 2018. Under the new guidance, equity investments (excluding those accounted for under the equity method or those that result in consolidation) are required to be measured at fair value, with changes in fair value recognized in net income. The new guidance also amends certain disclosure requirements associated with the fair value of financial instruments and requires financial assets and financial liabilities to be presented separately in the notes to the financial statements, grouped by measurement category and form of financial assets. SCE adopted this guidance effective January 1, 2018 and recognized a cumulative effect adjustment to increase the opening balance of retained earnings and accumulated other comprehensive loss by $5 million ($8 million pre-tax) on January 1, 2018.

In August and November 2016, the FASB issued two accounting standards updates to clarify the presentation and classification of certain cash receipts and payments in the statement of cash flows and to require restricted cash to be presented with cash and cash equivalents in the statement of cash flows. SCE adopted these standards effective January 1, 2018, using the retrospective approach. The adoption of these standards did not have a material impact on SCE's consolidated statement of cash flows.

In March 2017, the FASB issued an accounting standards update on the presentation of the components of net periodic benefit cost for an entity's defined benefit pension and other postretirement plans. SCE adopted this guidance retrospectively with respect to the income statement presentation requirement and prospectively for the capitalization requirement, effective January 1, 2018. The adoption of this standard did not have a material impact on SCE's consolidated financial statements, but did result in the separate presentation of service costs as an operating expense and non-service costs within other income and expenses and the limitation of the capitalization of benefit costs to the service cost component. During the year ended December 31, 2017 and 2016, SCE's non-service benefits of $51 million and $35 million were reclassified from operating expenses to other income and expenses. For FERC reporting purposes, all components of net periodic benefit costs continue to be recorded as operation expenses in account number 926. In addition, FERC has allowed entities to capitalize all components of net periodic benefit costs or elect to capitalize only the service cost component. SCE adopted this FERC guidance effective January 1, 2018 and elected to limit the capitalization of net periodic benefit costs to the service cost component, which resulted in an increase in SCE's 2018 rate base and a decrease in the 2018 transmission revenue requirement.

Accounting Guidance Not Yet Adopted

In February 2016, the FASB issued an accounting standards update related to lease accounting and further amended the standard in 2018. The new guidance is effective January 1, 2019. Under the new standard, a lease is defined as a contract, or part of a contract, that conveys the right to control the use of identified assets and obtain all the economic benefits for a period of time in exchange for consideration. Lessees are required to recognize leases on the balance sheet as a right-of-use asset and a related lease liability, and classify the leases as either operating or finance. The liability will be equal to the present value of the lease payments. The asset will be based on the liability, subject to adjustments, such as lease incentives. SCE, as a regulated entity, is permitted to continue to recognize expense using the timing that conforms to the regulatory rate treatment. In accordance with the new guidance, SCE will elect the package of practical expedients not to reassess prior conclusions related to contracts containing leases, lease classification, and initial direct costs and the practical expedient not to assess whether existing land easements are or contain a lease. SCE will adopt this guidance effective January 1, 2019, using the modified retrospective approach, for leases that existed as of the adoption date and will elect the optional transition method not to restate periods prior to the adoption date. The adoption of this standard is expected to increase right-of-use assets and lease liabilities in the consolidated balance sheets by approximately $1 billion as of January 1, 2019 for SCE. SCE has implemented a new lease accounting system and is in the process of finalizing the impact this standard will have on the lease disclosures. For FERC reporting purposes, operating leases are not required to be capitalized and reported in the balance sheet. However, SCE has elected to report operating leases in the FERC balance sheet using the accounts established for capital leases. In addition, the depreciation of capital leases and the amortization of interest expense associated with the lease obligations are not recognized under FERC. Instead, capital lease payments are recorded and reflected as power purchase expense for FERC reporting purposes.

The FASB issued an accounting standards update in June 2016, and further amended the guidance in November 2018, related to the impairment of financial instruments, effective January 1, 2020. The new guidance provides an impairment model, known as the current expected credit loss model, which is based on expected credit losses rather than incurred losses. SCE is currently evaluating the impact of this new guidance.

In February 2018, the FASB issued an accounting standards update to provide entities an election to reclassify stranded tax effects resulting from Tax Reform from accumulated other comprehensive income to retained earnings. Stranded tax effects originated in December 2017 when deferred taxes were re-measured at the lower federal corporate tax rate with the impact included in operating income but the tax effects of items within accumulated other comprehensive income were not similarly adjusted. Under GAAP and FERC, SCE will adopt this guidance on January 1, 2019 and reclassify stranded tax effects of $5 million from accumulated other comprehensive income to retained earnings in the period of adoption.

In August 2018, the FASB issued an accounting standards update which aligns the requirement for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing costs incurred to develop or obtain internal-use software. The guidance also clarified presentation requirements for reporting implementation costs in the financial statements. The guidance is effective January 1, 2020 with early adoption permitted. SCE is currently evaluating the impact of the guidance.

In August 2018, the FASB issued two accounting standards updates to remove, modify, and add certain disclosure requirements related to fair value measurement and employer-sponsored defined benefit pension or other postretirement plans. The guidance is effective January 1, 2020 and 2021, respectively, with early adoption permitted. SCE is currently evaluating the impact of the guidance.

Property, Plant and Equipment

Capitalized Software Costs

SCE capitalizes costs incurred during the application development stage of internal use software projects to property, plant, and equipment. SCE amortizes capitalized software costs ratably over the expected lives of the software, primarily ranging from 5 to 7 years and commencing upon operational use. Capitalized software costs, included in general plant and other above, were $1.0 billion and $1.1 billion at December 31, 2018 and 2017, respectively, and accumulated amortization was $0.5 billion and $0.6 billion, at December 31, 2018 and 2017, respectively. Amortization expense for capitalized software was $198 million, $233 million and $249 million in 2018, 2017 and 2016, respectively. At December 31, 2018, amortization expense is estimated to be $180 million, $145 million, $107 million, $59 million and $20 million for 2019 through 2023, respectively.

Jointly Owned Utility Projects

SCE owns undivided interests in several generating assets for which each participant provides its own financing. SCE's proportionate share of these assets 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 asset as of December 31, 2018:

(in millions)	Plant in Service	Construction Work in Progress	Accumulated Depreciation	Nuclear Fuel (at amortized cost)	Net Book Value	Ownership Interest
Transmission systems:						
Eldorado	$ 245	$ 13	$ 29	$ —	$ 229	59%
Pacific Intertie	217	73	75	—	215	50%
Generating station:						
Palo Verde (nuclear)	2,024	63	1,567	130	650	16%
Total	$ 2,486	$ 149	$ 1,671	$ 130	$ 1,094	

In addition, SCE has ownership interests in jointly owned power poles with other companies.

Variable Interest Entities

A VIE is defined as a legal entity that meets one of two conditions: (1) the equity owners do not have sufficient equity at risk, or (2) the holders of the equity investment at risk, as a group, lack any of the following three characteristics: decision-making rights, the obligation to absorb losses, or the right to receive the expected residual returns of the entity. The primary beneficiary is identified as the variable interest holder that has both the power to direct the activities of the VIE that most significantly impact the entity's economic performance and the obligation to absorb losses or the right to receive benefits from the entity that could potentially be significant to the VIE. The primary beneficiary is required to consolidate the VIE. Commercial and operating activities are generally the factors that most significantly impact the economic performance of such VIEs. Commercial and operating activities include construction, operation and maintenance, fuel procurement, dispatch and compliance with regulatory and contractual requirements.

Variable Interest in VIEs that are not Consolidated

Power Purchase Agreements

SCE has PPAs that are classified as variable interests in VIEs, including tolling agreements through which SCE provides the natural gas to fuel the plants and contracts with qualifying facilities that contain variable pricing provisions based on the price of natural gas. SCE has concluded that it is not the primary beneficiary of these VIEs since it does not control the commercial and operating activities of these entities. Since payments for capacity are the primary source of income, the most significant economic activity for these VIEs is the operation and maintenance of the power plants.

As of the balance sheet date, the carrying amount of assets and liabilities in SCE's consolidated balance sheet that relate to involvement with VIEs result from amounts due under the PPAs. Under these contracts, SCE recovers the costs incurred through demonstration of compliance with its CPUC-approved long-term power procurement plans. SCE has no residual interest in the entities and has not provided or guaranteed any debt or equity support, liquidity arrangements, performance guarantees or other commitments associated with these contracts other than the purchase commitments. As a result, there is no significant potential exposure to loss to SCE from its variable interest in these VIEs. The aggregate contracted capacity dedicated to SCE from these VIE projects was 3,602 megawatts ("MW") and 4,898 MW at December 31, 2018 and 2017, respectively, and the amounts that SCE paid to these projects were $762 million and $767 million for the years ended December 31, 2018 and 2017, respectively. These amounts are recoverable in customer rates, subject to reasonableness review.

Unconsolidated Trusts of SCE

SCE Trust II, Trust III, Trust IV, Trust V and Trust VI were formed in 2013, 2014, 2015, 2016 and 2017, respectively, for the exclusive purpose of issuing the 5.10%, 5.75%, 5.375%, 5.45% and 5.00% trust preference securities, respectively ("trust securities"). The trusts are VIEs. SCE has concluded that it is not the primary beneficiary of these VIEs as it does not have the obligation to absorb the expected losses or the right to receive the expected residual returns of the trusts. SCE Trust II, Trust III, Trust IV, Trust V and Trust VI issued to the public trust securities in the face amounts of $400 million, $275 million, $325 million, $300 million, and $475 million (cumulative, liquidation amounts of $25 per share), respectively, and $10,000 of common stock each to SCE. The trusts invested the proceeds of these trust securities in Series G, Series H, Series J, Series K and Series L Preference Stock issued by SCE in the principal amounts of $400 million, $275 million, $325 million, $300 million, and $475 million (cumulative, $2,500 per share liquidation values), respectively, which have substantially the same payment terms as the respective trust securities. The Series G, Series H, Series J, Series K, and Series L Preference Stock and the corresponding trust securities do not have a maturity date. Upon any redemption of any shares of the Series G, Series H, Series J, Series K or Series L Preference Stock, a corresponding dollar amount of trust securities will be redeemed by the applicable trust. The applicable trust will make distributions at the same rate and on the same dates on the applicable series of trust securities if and when the SCE board of directors declares and makes dividend payments on the related Preference Stock. The applicable trust will use any dividends it receives on the related Preference Stock to make its corresponding distributions on the applicable series of trust securities. If SCE does not make a dividend payment to any of these trusts, SCE would be prohibited from paying dividends on its common stock. SCE has fully and unconditionally guaranteed the payment of the trust securities and trust distributions, if and when SCE pays dividends on the related Preference Stock.

SCE formed Trust I, a VIE, in 2012 for the exclusive purpose of issuing 5.625% trust preference securities. SCE Trust I issued trust securities in the face amounts of $475 million to the public and $10,000 of common stock to SCE. SCE Trust I invested the proceeds of these trust securities in Series F Preference Stock issued by SCE in the principal amount of $475 million. In July 2017, all of the outstanding Series F Preference Stock was redeemed, and accordingly, SCE Trust I redeemed $475 million of trust securities from the public and $10,000 of common stock from SCE. As a result in September 2017, SCE Trust I was terminated.

The Trust II, Trust III, Trust IV, Trust V and Trust VI balance sheets as of December 31, 2018 and 2017, consisted of investments of $400 million, $275 million, $325 million, $300 million, and $475 million in the Series G, Series H, Series J, Series K and Series L Preference Stock, respectively, $400 million, $275 million, $325 million, $300 million, and $475 million of trust securities, respectively, and $10,000 each of common stock.

The following table provides a summary of the trusts' income statements:

	Years ended December 31,					
(in millions)	Trust I	Trust II	Trust III	Trust IV	Trust V	Trust VI
2018						
Dividend income	*	$ 20	$ 16	$ 17	$ 16	$ 24
Dividend distributions	*	20	16	17	16	24
2017						
Dividend income	$ 14	$ 20	$ 16	$ 17	$ 16	$ 12
Dividend distributions	14	20	16	17	16	12
2016						
Dividend income	$ 27	$ 20	$ 16	$ 17	$ 13	*
Dividend distributions	27	20	16	17	13	*

* Not applicable

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 considers assumptions that market participants would use in pricing the asset or liability, including assumptions about nonperformance risk. As of December 31, 2018 and 2017, nonperformance risk was not material for SCE.

Assets and liabilities are categorized into a three-level fair value hierarchy based on valuation inputs used to determine fair value.

Level 1 – The fair value of SCE's Level 1 assets and liabilities is determined using unadjusted quoted prices in active markets that are available at the measurement date for identical assets and liabilities. This level includes exchange-traded equity securities, U.S. treasury securities, mutual funds and money market funds.

Level 2 –SCE's Level 2 assets and liabilities include fixed income securities, primarily consisting of U.S. government and agency bonds, municipal bonds and corporate bonds, and over-the-counter derivatives. The fair value of fixed income securities is determined using a market approach by obtaining quoted prices for similar assets and liabilities in active markets and inputs that are observable, either directly or indirectly, for substantially the full term of the instrument.

The fair value of SCE's over-the-counter derivative contracts is determined using an income approach. SCE uses standard pricing models to determine the net present value of estimated future cash flows. Inputs to the pricing models include forward published or posted clearing prices from an exchange (Intercontinental Exchange) for similar instruments and discount rates. A primary price source that best represents trade activity for each market is used to develop observable forward market prices in determining the fair value of these positions. Broker quotes, prices from exchanges or comparison to executed trades are used to validate and corroborate the primary price 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.

Level 3 – The fair value of SCE's Level 3 assets and liabilities is determined using the income approach through various models and techniques that require significant unobservable inputs. This level includes derivative contracts that trade infrequently such as congestion revenue rights ("CRRs").

Assumptions are made in order to value derivative contracts in which observable inputs are not available. In circumstances where fair value cannot be verified with observable market transactions, it is possible that a different valuation model could produce a materially different estimate of fair value. Modeling methodologies, inputs, and techniques are reviewed and assessed as markets continue to develop and more pricing information becomes available and the fair value is adjusted when it is concluded that a change in inputs or techniques would result in a new valuation that better reflects the fair value of those derivative contracts.

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

	December 31, 2018				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ 32	$ 141	$ —	$ 173
Other	9	21	—	—	30
Nuclear decommissioning trusts:					
Stocks[2]	1,382	—	—	—	1,382
Fixed Income[3]	1,001	1,665	—	—	2,666
Short-term investments, primarily cash equivalents	120	95	—	—	215
Subtotal of nuclear decommissioning trusts[4]	2,503	1,760	—	—	4,263
Total assets	2,512	1,813	141	—	4,466
Liabilities at fair value					
Derivative contracts	—	13	—	(7)	6
Total liabilities	—	13	—	(7)	6
Net assets	$ 2,512	$ 1,800	$ 141	$ 7	$ 4,460

	December 31, 2017				
(in millions)	Level 1	Level 2	Level 3	Netting and Collateral[1]	Total
Assets at fair value					
Derivative contracts	$ —	$ 9	$ 102	$ (1)	$ 110
Money market funds and other	495	—	—	—	495
Nuclear decommissioning trusts:					
Stocks[2]	1,596	—	—	—	1,596
Fixed Income[3]	1,065	1,665	—	—	2,730
Short-term investments, primarily cash equivalents	101	72	—	—	173
Subtotal of nuclear decommissioning trusts[4]	2,762	1,737	—	—	4,499
Total assets	3,257	1,746	102	(1)	5,104
Liabilities at fair value					
Derivative contracts	—	2	1	(2)	1
Total liabilities	—	2	1	(2)	1
Net assets	$ 3,257	$ 1,744	$ 101	$ 1	$ 5,103

1 Represents the netting of assets and liabilities under master netting agreements and cash collateral.

2 Approximately 71% and 69% of SCE's equity investments were located in the United States at December 31, 2018 and 2017, respectively.

3 Includes corporate bonds, which were diversified and included collateralized mortgage obligations and other asset backed securities of $67 million and $102 million at December 31, 2018 and 2017, respectively.

4 Excludes net payables of $143 million and $59 million at December 31, 2018 and 2017, respectively, which consist of interest and dividend receivables as well as receivables and payables related to SCE's pending securities sales and purchases.

Fair Value of Level 3

The following table sets forth a summary of changes in SCE's fair value of Level 3 net derivative assets and liabilities:

	December 31,	
(in millions)	2018	2017
Fair value of net assets (liabilities) at beginning of period	$ 101	$ (1,089)
Total realized/unrealized gains:		
Included in regulatory assets and liabilities[1]	40	133
Contract amendment[2]	—	143
Normal purchase and normal sale designation[3]	—	914
Fair value of net assets at end of period	$ 141	$ 101
Change during the period in unrealized gains and losses related to assets and liabilities held at the end of the period	$ 138	$ 100

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

2 Represents a tolling contract that was amended during the second quarter of 2017, which was no longer accounted for as a derivative as of December 31, 2017.

3 During the third quarter of 2017, SCE designated certain derivative contracts as normal purchase and normal sale contracts, which resulted in a reclassification of $914 million from derivative liabilities to other liabilities. These liabilities are amortized over the remaining contract terms.

SCE recognizes the fair value for transfers in and transfers out of each level at the end of each reporting period. There were no material transfers between any levels during 2018 and 2017.

Valuation Techniques Used to Determine Fair Value

The process of determining fair value is the responsibility of SCE's risk management department, which reports to SCE's chief financial officer. This department obtains observable and unobservable inputs through broker quotes, exchanges and internal valuation techniques that use both standard and proprietary models to determine fair value. Each reporting period, the risk and finance departments collaborate to determine the appropriate fair value methodologies and classifications for each derivative. Inputs used and valuations are reviewed period-over-period and compared with market conditions to determine reasonableness.

The following table sets forth SCE's valuation techniques and significant unobservable inputs used to determine fair value for significant Level 3 assets and liabilities:

	Fair Value (in millions)			Significant	
	Assets	Liabilities	Valuation Technique(s)	Unobservable Input	Range
Congestion revenue rights					
December 31, 2018	$ 141	$ —	Auction prices	CAISO CRR auction clearing prices	$(7.41) - $41.52
December 31, 2017	102	—	Auction prices	CAISO CRR auction clearing prices	$(9.41) - $8.66

Level 3 Fair Value Sensitivity

For CRRs, increases or decreases in CAISO auction price would result in higher or lower fair value, respectively.

Nuclear Decommissioning Trusts

SCE's 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. There are no securities classified as Level 3 in the nuclear decommissioning trusts. SCE's investment policies and CPUC requirements place limitations on the types and investment grade ratings of the securities that may be held by the nuclear decommissioning trust funds. These policies restrict the trust funds from holding alternative investments and limit the trust funds' exposures to investments in highly illiquid markets. With respect to equity and fixed income securities, the trustee obtains prices from third-party pricing services which SCE is able to independently corroborate as described below. The trustee monitors prices supplied by pricing services, including reviewing prices against defined parameters' tolerances and performs research and resolves variances beyond the set parameters. SCE corroborates the fair values of securities by comparison to other market-based price sources obtained by SCE's investment managers. Differences outside established thresholds are followed-up with the trustee and resolved. For each reporting period, SCE reviews the trustee determined fair value hierarchy and overrides the trustee level classification when appropriate.

Fair Value of Debt Recorded at Carrying Value

The carrying value and fair value of SCE's long-term debt (including current portion of long-term debt) are as follows:

	December 31, 2018		December 31, 2017	
(in millions)	Carrying Value[1]	Fair Value[2]	Carrying Value[1]	Fair Value[2]
SCE	12,971	13,180	10,907	12,547

1 Carrying value is net of debt issuance costs.

2 The fair value of SCE's short-term and long-term debt is classified as Level 2.

Debt and Credit Agreements

Long-Term Debt

SCE long-term debt maturities over the next five years are the following:

(in millions)	
2019	$ 79
2020	79
2021	1,029
2022	364
2023	900

Liens and Security Interests

Almost all of SCE's properties are subject to a trust indenture lien. SCE has pledged first and refunding mortgage bonds as collateral for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE has a debt covenant that requires a debt to total capitalization ratio to be less than or equal to 0.65 to 1. At December 31, 2018, SCE was in compliance with this debt covenant and all other financial covenants that affect access to capital.

Credit Agreements and Short-Term Debt

The following table summarizes the status of the credit facilities at December 31, 2018:

(in millions)		
Commitment	$	3,000
Outstanding borrowings (excluding discount)		(721)
Outstanding letters of credit		(190)
Amount available	$	2,089

In May 2018, SCE amended its multi-year revolving credit facility to increase the facilities to $3.0 billion from $2.75 billion. The facility matures in May 2023 and has two 1-year extension options. SCE's credit facility is generally used to support commercial paper borrowings and letters of credit issued for procurement-related collateral requirements, balancing account undercollections and for general corporate purposes, including working capital requirements to support operations and capital expenditures.

At December 31, 2018, commercial paper, net of discount, was $720 million at a weighted-average interest rate of 3.23%.

At December 31, 2018, letters of credit issued under SCE's credit facility aggregated $190 million and are scheduled to expire in twelve months or less. At December 31, 2017, the outstanding commercial paper, net of discount, was $738 million at a weighted-average interest rate of 1.75%. In December 2017, SCE borrowed $500 million from the credit facility which had an interest rate of 2.46% on December 31, 2017; this borrowing was repaid in January 2018 with cash on hand.

In February 2019, SCE borrowed $750 million under a Term Loan Agreement due in February 2020, with a variable interest rate based on the London Interbank Offered Rate plus 70 basis points. In March 2019, SCE issued $500 million of 4.20% first and refunding mortgage bonds due 2029 and $600 million of 4.875% first and refunding mortgage bonds due 2049. The proceeds from the Term Loan and the March issuances were used to repay commercial paper borrowings and for general corporate purposes.

Derivative Instruments

Derivative financial instruments are used to manage exposure to commodity price risk. These risks are managed in part by entering into forward commodity transactions, including options, swaps and futures. To mitigate credit risk from counterparties in the event of nonperformance, master netting agreements are used whenever possible 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

Commodity price risk represents the potential impact that can be caused by a change in the market value of a particular commodity. SCE's electricity price exposure arises from energy purchased from and sold to wholesale markets as a result of differences between SCE's load requirements and the amount of energy delivered from its generating facilities and PPAs. SCE's natural gas price exposure arises from natural gas purchased for the Mountainview power plant and peaker plants, qualifying facility contracts where pricing is based on a monthly natural gas index and PPAs in which SCE has agreed to provide the natural gas needed for generation, referred to as tolling arrangements.

Credit and Default Risk

Credit and default risk represent the potential impact that can be caused if a counterparty were to default on its contractual obligations and SCE would be exposed to 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 the sales of excess power and realized gains on derivative instruments.

Certain power and gas contracts contain master netting agreements or similar agreements, which generally allow counterparties subject to the agreement to offset amounts when certain criteria are met, such as in the event of default. The objective of netting is to reduce credit exposure. Additionally, to reduce SCE's risk exposures counterparties may be required to pledge collateral depending on the creditworthiness of each counterparty and the risk associated with the transaction.

Certain power and gas contracts contain a provision that requires SCE to maintain an investment grade 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 post additional collateral to cover derivative liabilities and the related outstanding payables. The net fair value of all derivative liabilities with these credit-risk-related contingent features was $4 million and $1 million as of December 31, 2018 and 2017, respectively, for which SCE has posted collateral of $17 million and less than $1 million collateral to its counterparties at the respective dates for its derivative liabilities and related outstanding payables. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2018, SCE would be required to post less than $1 million of additional collateral.

Fair Value of Derivative Instruments

SCE presents its derivative assets and liabilities on a net basis on its consolidated balance sheets when subject to master netting agreements or similar agreements. Derivative positions are also offset against margin and cash collateral deposits. In addition, SCE has provided collateral in the form of letters of credit. Collateral requirements can vary depending upon the level of unsecured credit extended by counterparties, changes in market prices relative to contractual commitments and other factors. The following table summarizes the gross and net fair values of SCE's commodity derivative instruments:

	December 31, 2018						
	Derivative Assets			Derivative Liabilities			Net Asset
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 171	$ 2	$ 173	$ 13	$ —	$ 13	$ 160
Gross amounts offset in the consolidated balance sheets	—	—	—	—	—	—	—
Cash collateral posted	—	—	—	(7)	—	(7)	7
Net amounts presented in the consolidated balance sheets	$ 171	$ 2	$ 173	$ 6	$ —	$ 6	$ 167

	December 31, 2017						
	Derivative Assets			Derivative Liabilities			Net Asset
(in millions)	Short-Term	Long-Term	Subtotal	Short-Term	Long-Term	Subtotal	
Commodity derivative contracts							
Gross amounts recognized	$ 106	$ 5	$ 111	$ 3	$ —	$ 3	$ 108
Gross amounts offset in the consolidated balance sheets	(1)	—	(1)	(1)	—	(1)	—
Cash collateral posted	—	—	—	(1)	—	(1)	1
Net amounts presented in the consolidated balance sheets	$ 105	$ 5	$ 110	$ 1	$ —	$ 1	$ 109

Income Statement Impact of Derivative Instruments

SCE recognizes realized gains and losses on derivative instruments as purchased power expense and expects that such gains or losses will be part of the purchased power costs recovered from customers. As a result, realized gains and losses do not affect earnings, but may temporarily affect cash flows. Due to expected future recovery from customers, unrealized gains and losses are recorded as regulatory assets and liabilities and therefore also do not affect earnings. The remaining effects of derivative activities and related regulatory offsets are reported in cash flows from operating activities in the consolidated statements of cash flows.

The following table summarizes the components of SCE's economic hedging activity:

	Years ended December 31,		
(in millions)	2018	2017	2016
Realized gains (losses)	$ 26	$ (14)	$ (59)
Unrealized gains	82	106	84

Notional Volumes of Derivative Instruments

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

		Economic Hedges	
	Unit of	December 31,	
Commodity	Measure	2018	2017
Electricity options, swaps and forwards	GWh	2,786	475
Natural gas options, swaps and forwards	Bcf	20	143
Congestion revenue rights	GWh	54,453	78,765

Income Taxes

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. Flow-through items reduce current authorized revenue requirements in SCE's rate cases and result in a regulatory asset for recovery of deferred income taxes in future periods. The difference between the authorized amounts as determined in SCE's rate cases, adjusted for balancing and memorandum account activities, and the recorded flow-through items also result in increases or decreases in regulatory assets with a corresponding impact on the effective tax rate to the extent that recorded deferred amounts are expected to be recovered in future rates.

Tax Reform

On December 22, 2017, Tax Reform was signed into law. This comprehensive reform of tax law reduces the federal corporate income tax rate from 35% to 21% and is generally effective beginning January 1, 2018. US GAAP and FERC require deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. At the date of enactment, SCE's deferred taxes were re-measured based upon the new tax rate. In December 2017, accumulated deferred income tax liabilities, net, were reduced by $5.0 billion at SCE. Changes to bonus depreciation rules under Tax Reform had an immaterial impact on SCE's statement of income and balance sheet.

In the absence of regulatory guidance specific to 2017 Tax Reform, SCE used judgment to interpret prior Commission decisions in determining which re-measurement amounts belong to customers and shareholders. An income tax expense of $33 million was recorded for the re-measurement of deferred taxes attributable to shareholder-funded activities in 2017. Changes in the allocation of deferred tax re-measurement between customers and shareholders will be reflected in the financial statements and adjusted prospectively as information becomes available. The CPUC issued a resolution in February 2019 holding that customers are only entitled to excess deferred taxes which were included when setting rates, and that all other deferred tax re-measurement belongs to shareholders. As a result of this resolution, an income tax benefit of approximately $70 million is expected to be recorded in the first quarter of 2019.

Excess Deferred Taxes

The re-measurement of deferred taxes at SCE was primarily recorded as an excess deferred tax benefit to regulatory liabilities or an offset to regulatory assets since pre-tax amounts giving rise to the deferred taxes were created through ratemaking activities. FERC accounts 190, 282, 283, and 254 were impacted as the deferred tax balances in these accounts were reclassified to regulatory liabilities. Since the majority of SCE's deferred taxes arise from property-related differences, SCE estimates that the excess deferred tax benefits will be refunded to customers over approximately 40 or more years. SCE has open rate proceedings with both the CPUC and FERC to resolve both the timing and amounts to be refunded to customers.

As of December 31, 2018, $2.8 billion of excess accumulated deferred income tax liabilities (including gross-up) associated with Tax Reform were recorded in FERC account 254, which are summarized in the table below.

(in millions)	December 31,2017	Other Adjustments[2]	ARAM Amortization[3]	December 31,2018
CPUC				
Property				
Protected	$ 1,551	$ 21	$ (31)	$ 1,541
Unprotected	116	(1)	(21)	94
Cost of Removal	(268)	(12)	6	(274)
Other				
Rate Base	(5)	(1)	6	-
Other Deferred Taxes	107	(34)	-	73
CPUC total	$ 1,501	$ (27)	$ (40)	$ 1,434
FERC				
Property				
Protected	$ 559	$ 11	$ (3)	$ 567
Unprotected	56	4	(7)	53
Cost of Removal	(38)	(18)	1	(55)
Other				
Rate Base	5	-	(5)	-
Other Deferred Taxes	-	-	-	-
FERC Total	$ 582	$ (3)	$ (14)	$ 565
Total excess deferred taxes	$ 2,083	$ (30)	$ (54)	$ 1,999
Gross Up on Excess Deferred Taxes				
CPUC	$ 583	$ (9)	$ (16)	$ 558
FERC	226	(2)	(5)	219
Total Gross Up	$ 809	$ (11)	$ (21)	$ 777
Total FERC Account 254[1]	$ 2,892	$ (41)	$ (75)	$ 2,776

1 Excess deferred taxes were recorded in FERC account 254.

2 Adjustments to the opening balances at December 31, 2017 resulted from the filing of the 2017 tax returns in 2018.

3 The amortization of excess deferred taxes was recorded in FERC account 411.1.

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 available evidence indicates it is more likely than not, based solely on the technical merits, that the position will be sustained upon examination. 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 portion of affirmative claims.

Unrecognized Tax Benefits

The following table provides a reconciliation of unrecognized tax benefits:

	December 31,		
(in millions)	2018	2017	2016
Balance at January 1,	$ 331	$ 371	$ 353
Tax positions taken during the current year:			
Increases	42	51	36
Tax positions taken during a prior year:			
Increases	—	—	—
Decreases[1]	(121)	(13)	(18)
Decreases for settlements during the period[2]	(3)	(78)	—
Balance at December 31,	$ 249	$ 331	$ 371

1 Decrease in 2018 was related to re-measurement as a result of a settlement with the California Franchise Tax Board for tax years 1994 – 2006. Decrease in 2016 was related to state tax receivables on various claims. Due to the tax risks associated with these claims, the tax benefits were fully reserved at the time the asset was recorded. During 2016, the Company determined that it will not recognize these assets, so the tax benefit and related tax reserve were written off.

2 In 2018, SCE reached a settlement with the California Franchise Tax Board for tax years 1994 – 2006. In 2017, all open tax positions with the IRS for taxable years 2007 – 2012 were settled. See Tax Disputes below for further details.

As of December 31, 2018, 2017 and 2016, if recognized, $95 million, $167 million, and $243 million, respectively, of the unrecognized tax benefits would impact SCE's effective tax rate.

Tax Disputes

In 2017, SCE settled all open tax positions with the IRS for tax years 2007 – 2012. SCE has previously made cash deposits to cover the estimated tax and interest liability from this audit cycle and expects a $26 million refund of this deposited amount.

Tax years that remain open for examination by the IRS and the California Franchise Tax Board are 2015 – 2017 and 2010 – 2017, respectively. SCE has settled all open tax positions with the IRS for taxable years prior to 2013.

In the fourth quarter of 2018, SCE reached a settlement with the California Franchise Tax Board for tax years 1994 – 2006 and has updated its uncertain tax positions to reflect this settlement. This update resulted in income tax benefits of $70 million at SCE. As a result of the settlement, SCE expects a refund of tax and interest from the California Franchise Tax Board in the amount of $101 million. Tax years 2007 – 2009 are currently under protest with the California Franchise Tax Board.

Accrued Interest and Penalties

The total amount of accrued interest and penalties related to income tax liabilities are $6 million and $41 million at December 31, 2018 and 2017, respectively.

The net after-tax interest and penalties recognized in income tax (benefit) expense are $(25) million, $4 million and $2 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Compensation and Benefit Plans

Employee Savings Plan

The 401(k) defined contribution savings plan is designed to supplement employees' retirement income. Employer contributions were $74 million, $69 million and $68 million for the years ended December 31, 2018, 2017 and 2016, respectively.

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) for SCE is approximately $57 million for the year ending December 31, 2019. Annual contributions made by SCE to most of SCE's pension plans are anticipated to be recovered through CPUC-approved regulatory mechanisms.

The funded position of pension is sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund pension are affected by movements in the equity and bond markets. Due to SCE's regulatory recovery treatment, a regulatory asset has been recorded equal to the unfunded status.

Information on pension plan assets and benefit obligations is shown below.

(in millions)	Years ended December 31, 2018	2017
Change in projected benefit obligation		
Projected benefit obligation at beginning of year	$ 3,702	$ 3,791
Service cost	121	129
Interest cost	124	144
Actuarial gain	(273)	(74)
Benefits paid	(243)	(288)
Projected benefit obligation at end of year	$ 3,431	$ 3,702
Change in plan assets		
Fair value of plan assets at beginning of year	$ 3,390	$ 3,172
Actual return on plan assets	(86)	442
Employer contributions	52	64
Benefits paid	(232)	(288)
Fair value of plan assets at end of year	$ 3,124	$ 3,390
Funded status at end of year	$ (307)	$ (312)
Amounts recognized in the consolidated balance sheets consist of [1]:		
Long-term assets	$ —	$ —
Current liabilities	(5)	(4)
Long-term liabilities	(302)	(308)
	$ (307)	$ (312)
Amounts recognized in accumulated other comprehensive loss consist of:		
Prior service cost	$ —	$ —
Net loss[1]	17	21
	$ 17	$ 21
Amounts recognized as a regulatory asset	271	271
Total not yet recognized as expense	$ 288	$ 292
Accumulated benefit obligation at end of year	$ 3,342	$ 3,585
Pension plans with an accumulated benefit obligation in excess of plan assets:		
Projected benefit obligation	$ 3,431	$ 3,702
Accumulated benefit obligation	3,342	3,585
Fair value of plan assets	3,124	3,390
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.19%	3.46%
Rate of compensation increase	4.10%	4.10%

1 The SCE liability excludes a long-term payable due to Edison International Parent of $117 million and $114 million at December 31, 2018 and 2017, respectively, related to certain SCE postretirement benefit obligations transferred to Edison International Parent. SCE's accumulated other comprehensive loss of $17 million and $21 million at December 31, 2018 and 2017, respectively, excludes net loss of $21 million and $19 million related to these benefits.

Net periodic pension expense components are:

	Years ended December 31,		
(in millions)	2018	2017	2016
Service cost	$ 123	$ 133	$ 136
Non-service cost			
Interest cost	128	149	156
Expected return on plan assets	(214)	(199)	(205)
Amortization of prior service cost	3	3	4
Amortization of net loss[1]	6	17	23
Regulatory adjustment (deferred)	15	(28)	(21)
Total non-service benefit	$ (62)	$ (58)	$ (43)
Total expense recognized	$ 61	$ 75	$ 93

1 Includes the amount of net loss reclassified from accumulated other comprehensive loss. The amount reclassified for SCE was $6 million for all the years ended December 31, 2018, 2017 and 2016.

Other changes in pension plan assets and benefit obligations recognized in other comprehensive loss are:

	Years ended December 31,		
(in millions)	2018	2017	2016
Net loss	$ 5	$ 3	$ 4
Amortization of net loss	(6)	(6)	(6)
Total recognized in other comprehensive loss	$ (1)	$ (3)	$ (2)
Total recognized in expense and other comprehensive loss	$ 60	$ 72	$ 91

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 SCE's postretirement benefit plans that are recoverable in utility rates.

The estimated pension amounts that will be amortized to expense in 2019 are as follows:

(in millions)	
Unrecognized net loss to be amortized[1]	$ 6
Unrecognized prior service cost to be amortized	2

1 The amount of net loss expected to be reclassified from accumulated other comprehensive loss for SCE is $6 million.

SCE used the following weighted-average assumptions to determine pension expense:

	Years ended December 31,		
	2018	2017	2016
Discount rate	3.46%	3.94%	4.18%
Rate of compensation increase	4.10%	4.00%	4.00%
Expected long-term return on plan assets	6.50%	6.50%	7.00%

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

(in millions)	Years ended December 31,
2019	$ 299
2020	289
2021	285
2022	281
2023	274
2024 – 2028	1,280

Postretirement Benefits Other Than Pensions ("PBOP(s)")

Employees hired prior to December 31, 2017 who are retiring at or after age 55 with at least 10 years of service may be eligible for postretirement medical, dental, and vision benefits. Eligibility for a company contribution toward the cost of these benefits in retirement depends on a number of factors, including the employee's years of service, age, hire date, and retirement date. Under the terms of the Edison International Welfare Benefit Plan ("PBOP Plan"), (which SCE participates in), is responsible for the costs and expenses of all PBOP Plan benefits with respect to its employees and former employees that exceed the participants' share of contributions. A participating employer may terminate the PBOP Plan benefits with respect to its employees and former employees, as may SCE (as PBOP Plan sponsor), and, accordingly, the participants' PBOP Plan benefits are not vested benefits.

The expected contributions (substantially all of which are expected to be made by SCE) for PBOP benefits are $23 million for the year ended December 31, 2019. Annual contributions related to SCE employees made to SCE plans are anticipated to be recovered through CPUC-approved regulatory mechanisms and are expected to be, at a minimum, equal to the total annual expense for these plans.

SCE has three voluntary employees' beneficiary association trusts ("VEBA Trusts") that can only be used to pay for retiree health care benefits of SCE and its subsidiaries. Once funded into the VEBA Trusts, SCE cannot subsequently recover remaining amounts in the VEBA Trusts. Participants of the PBOP Plan do not have a beneficial interest in the VEBA Trusts. The VEBA Trust assets are sensitive to changes in market conditions. Changes in overall interest rate levels significantly affect the company's liabilities, while assets held in the various trusts established to fund other postretirement benefits are affected by movements in the equity and bond markets. Due to SCE's regulatory recovery treatment, the unfunded status is offset by a regulatory asset.

Information on PBOP Plan assets and benefit obligations is shown below:

(in millions)	Years ended December 31, 2018	2017
Change in benefit obligation		
Benefit obligation at beginning of year	$ 2,325	$ 2,266
Service cost	37	31
Interest cost	80	85
Special termination benefits	—	1
Actuarial (gain) loss[1]	(379)	23
Plan participants' contributions	28	24
Benefits paid	(114)	(105)
Benefit obligation at end of year	$ 1,977	$ 2,325
Change in plan assets		
Fair value of plan assets at beginning of year	$ 2,330	$ 2,102
Actual return on assets	(123)	297
Employer contributions	12	12
Plan participants' contributions	28	24
Benefits paid	(114)	(105)
Fair value of plan assets at end of year	$ 2,133	$ 2,330
Funded status at end of year	$ 156	$ 5
Amounts recognized in the consolidated balance sheets consist of:		
Long-term assets	$ 168	$ 17
Current liabilities	(12)	(12)
	$ 156	$ 5
Amounts recognized in accumulated other comprehensive loss consist of:		
Amounts recognized as a regulatory liability	$ (185)	$ (26)
Total not yet recognized as income	$ (185)	$ (26)
Weighted-average assumptions used to determine obligations at end of year:		
Discount rate	4.35%	3.70%
Assumed health care cost trend rates:		
Rate assumed for following year	6.75%	6.75%
Ultimate rate	5.00%	5.00%
Year ultimate rate reached	2029	2029

[1] For SCE, the 2018 actuarial gain is primarily related to $194 million gain from an increase in discount rate (from 3.70% as of December 31, 2017 to 4.35% as of December 31, 2018) and $135 million in experience gain.

Net periodic PBOP expense components are:

(in millions)	Years ended December 31, 2018	2017	2016
Service cost	$ 37	$ 31	$ 34
Non-service cost			
Interest cost	80	85	97
Expected return on plan assets	(122)	(110)	(112)
Special termination benefits[1]	—	1	2
Amortization of prior service credit	(1)	(2)	(2)
Regulatory adjustment (deferred)	24	—	—
Total non-service benefit	$ (19)	$ (26)	$ (15)
Total expense	$ 18	$ 5	$ 19

1 Due to the reduction in workforce, SCE has incurred costs for extended retiree health care coverage.

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 SCE's postretirement benefit plans that are recoverable in utility rates. The estimated unrecognized net gain and prior service credit to be amortized in 2019 are $3 million and $1 million, respectively.

SCE used the following weighted-average assumptions to determine PBOP expense:

	Years ended December 31, 2018	2017	2016
Discount rate	3.70%	4.29%	4.55%
Expected long-term return on plan assets	5.30%	5.30%	5.60%
Assumed health care cost trend rates:			
Current year	6.75%	7.00%	7.50%
Ultimate rate	5.00%	5.00%	5.00%
Year ultimate rate reached	2029	2022	2022

A one-percentage-point change in assumed health care cost trend rate would have the following effects:

(in millions)	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on accumulated benefit obligation as of December 31, 2018	$ 209	$ (172)
Effect on annual aggregate service and interest costs	11	(9)

The following benefit payments (net of plan participants' contributions) are expected to be paid:

(in millions)	Years ended December 31,
2019	$ 91
2020	94
2021	97
2022	99
2023	102
2024 – 2028	550

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 2018 pension plan assets were 25% for U.S. equities, 17% for non-U.S. equities, 40% for fixed income, 12% for opportunistic and/or alternative investments and 6% for other investments. Target allocations for 2018 PBOP plan assets (except for Represented VEBA which is 85% for fixed income, 5% for opportunistic/private equities, and 10% global equities) are 58% for global equities, 29% for fixed income, and 13% for opportunistic and/or alternative investments. SCE 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 classes and individual manager performances are measured against targets. SCE 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 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

SCE's capital markets return forecast methodologies primarily use a combination of historical market data, current market conditions, proprietary forecasting expertise, complex models to develop asset class return forecasts and a building block approach. The forecasts are developed using variables such as real risk-free interest, inflation, and asset class specific risk premiums. For equities, the risk premium is based on an assumed average equity risk premium of 5% over cash. The forecasted return on private equity and opportunistic investments are estimated at a 2% premium above public equity, reflecting a premium for higher volatility and lower liquidity. For fixed income, the risk premium is based on a comprehensive modeling of credit spreads.

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. The fair value of the underlying investments in equity mutual funds are based on stock-exchange prices. The fair value of the underlying investments in 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. Common/collective funds and partnerships are measured at fair value using the net asset value per share ("NAV") and have not been classified in the fair value hierarchy. Other investment entities are valued similarly to common/collective funds and are therefore classified as NAV. The Level 1 registered investment companies are either mutual or money market funds. The remaining funds in this category are readily redeemable and classified as NAV.

SCE reviews the process/procedures of both the pricing services and the trustee to gain an understanding of the inputs/assumptions and valuation techniques used to price each asset type/class. The trustee and SCE's validation procedures for pension and PBOP equity and fixed income securities are the same as the nuclear decommissioning trusts. The values of Level 1 mutual and money market funds are publicly quoted. The trustees obtain the values of common/collective and other investment funds from the fund managers. The values of partnerships are based on partnership valuation statements updated for cash flows. SCE's investment managers corroborate the trustee fair values.

Pension Plan

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2018 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	NAV[1]	Total
U.S. government and agency securities[2]	$ 110	$ 937	$ —	$ —	$ 1,047
Corporate stocks[3]	473	6	—	—	479
Corporate bonds[4]	—	582	—	—	582
Common/collective funds[5]	—	—	—	426	426
Partnerships/joint ventures[6]	—	—	—	434	434
Other investment entities[7]	—	—	—	236	236
Registered investment companies[8]	112	—	—	2	114
Interest-bearing cash	2	—	—	—	2
Other	—	73	—	—	73
Total	$ 697	$ 1,598	$ —	$ 1,098	$ 3,393
Receivables and payables, net					(72)
Net plan assets available for benefits					$ 3,321
SCE's share of net plan assets					$ 3,124

The following table sets forth the Master Trust investments that were accounted for at fair value as of December 31, 2017 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	NAV[1]	Total
U.S. government and agency securities[2]	$ 184	$ 507	$ —	$ —	$ 691
Corporate stocks[3]	718	11	—	—	729
Corporate bonds[4]	—	676	—	—	676
Common/collective funds[5]	—	—	—	705	705
Partnerships/joint ventures[6]	—	—	—	396	396
Other investment entities[7]	—	—	—	262	262
Registered investment companies[8]	140	—	—	—	140
Interest-bearing cash	9	—	—	—	9
Other	—	106	—	—	106
Total	$ 1,051	$ 1,300	$ —	$ 1,363	$ 3,714
Receivables and payables, net					(98)
Net plan assets available for benefits					$ 3,616
SCE's share of net plan assets					$ 3,390

1 These investments are measured at fair value using the net asset value per share practical expedient and have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the net plan assets available for benefits.

2 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.

3 Corporate stocks are diversified. At December 31, 2018 and 2017, respectively, performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (43%) and (54%) and Morgan Stanley Capital International (MSCI) index (57%) and (46%).

4 Corporate bonds are diversified. At December 31, 2018 and 2017, respectively, this category includes $60 million and $65 million for collateralized mortgage obligations and other asset backed securities.

5 At December 31, 2018 and 2017, respectively, the common/collective assets were invested in equity index funds that seek to track performance of the Standard and Poor's 500 Index (43% and 41%) and Russell 1000 indexes (14% and 15%). In addition, at December 31, 2018 and 2017, respectively, 21% and 15% of the assets in this category are in index funds which seek to track performance in the MSCI All Country World Index exUS and 15% and 25% of this category are in non-index U.S. equity fund, which is actively managed.

6 At December 31, 2018 and 2017, respectively, 50% and 55% are invested in private equity funds with investment strategies that include branded consumer products, clean technology and California geographic focus companies, 30% and 20% are invested in a broad range of financial assets in all global markets, and 16% and 23% are invested in publicly traded fixed income securities.

7 Other investment entities were primarily invested in (1) emerging market equity securities, (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, and (3) domestic mortgage backed securities.

8 Level 1 registered investment companies primarily consisted of a global equity mutual fund which seeks to outperform the MSCI World Total Return Index.

At December 31, 2018 and 2017, respectively, approximately 61% and 67% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

Postretirement Benefits Other than Pensions

The following table sets forth the VEBA Trust assets for SCE that were accounted for at fair value as of December 31, 2018 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	NAV[1]	Total
U.S. government and agency securities[2]	$ 322	$ 49	$ —	$ —	$ 371
Corporate stocks[3]	204	—	—	—	204
Corporate notes and bonds[4]	—	832	—	—	832
Common/collective funds[5]	—	—	—	495	495
Partnerships[6]	—	—	—	89	89
Registered investment companies[7]	38	—	—	—	38
Interest bearing cash	22	—	—	—	22
Other[8]	5	99	—	—	104
Total	$ 591	$ 980	$ —	$ 584	$ 2,155
Receivables and payables, net					(22)
Combined net plan assets available for benefits					$ 2,133

The following table sets forth the VEBA Trust assets for SCE that were accounted for at fair value as of December 31, 2017 by asset class and level within the fair value hierarchy:

(in millions)	Level 1	Level 2	Level 3	NAV[1]	Total
U.S. government and agency securities[2]	$ 398	$ 33	$ —	$ —	$ 431
Corporate stocks[3]	254	—	—	—	254
Corporate notes and bonds[4]	—	845	—	—	845
Common/collective funds[5]	—	—	—	569	569
Partnerships[6]	—	—	—	82	82
Registered investment companies[7]	37	—	—	—	37
Interest bearing cash	42	—	—	—	42
Other[8]	5	84	—	—	89
Total	$ 736	$ 962	$ —	$ 651	$ 2,349
Receivables and payables, net					(19)
Combined net plan assets available for benefits					$ 2,330

1 These investments are measured at fair value using the net asset value per share practical expedient and have not been classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the net plan assets available for benefits.

2 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.

3 Corporate stock performance for actively managed separate accounts is primarily benchmarked against the Russell Indexes (67% and 64%) and the MSCI All Country World Index (33% and 36%) for 2018 and 2017, respectively.

4 Corporate notes and bonds are diversified and include approximately $59 million and $36 million for commercial collateralized mortgage obligations and other asset backed securities at December 31, 2018 and 2017, respectively.

5 At December 31, 2018 and 2017, respectively, 74% and 75% of the common/collective assets are invested in index funds which seek to track performance in the MSCI All Country World Index Investable Market Index and 19% and 17% are invested in a non-index U.S. equity fund which is actively managed. The remaining assets in this category are primarily invested in emerging market fund.

6 At December 31, 2018 and 2017, respectively, 48% and 56% of the partnerships are invested in private equity and venture capital funds. Investment strategies for these funds include branded consumer products, clean and information technology and healthcare. 34% and 33% are invested in a broad range of financial assets in all global markets. 17% and 9% of the remaining partnerships category are invested in asset backed securities including distressed mortgages, distressed companies and commercial and residential loans and debt and equity of banks.

7 At both December 31, 2018 and 2017, registered investment companies were primarily invested in (1) a money market fund, (2) exchange rate trade funds which seek to track performance of MSCI Emerging Market Index, Russell 2000 Index, and international small cap equities.

8 Other includes $58 million and $60 million of municipal securities at December 31, 2018 and 2017, respectively.

At December 31, 2018 and 2017, respectively, approximately 64% and 61% of the publicly traded equity investments, including equities in the common/collective funds, were located in the United States.

Stock-Based Compensation

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, is 66 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. As of December 31, 2018, Edison International had approximately 28 million shares remaining available for new award grants under its stock-based compensation plans.

The following table summarizes total expense and tax benefits associated with stock-based compensation:

(in millions)	Years ended December 31,		
	2018	2017	2016
Stock-based compensation expense:			
Stock options	$ 6	$ 8	$ 7
Performance shares	1	2	6
Restricted stock units	4	3	3
Other	—	—	—
Total stock-based compensation expense	$ 11	$ 13	$ 16
Income tax benefits related to stock compensation expense	$ 3	$ 15	$ 20

Stock Options

Under the 2007 Performance Incentive Plan, stock options were granted at exercise prices equal to the closing price at the grant date. Stock options and other awards related to, or with a value derived from, its common stock may be granted 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. Additionally, cash awards will be substituted 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,		
	2018	2017	2016
Expected terms (in years)	5.7	5.7	5.9
Risk-free interest rate	2.6% - 3.0%	2.1% - 2.3%	1.2% – 2.2%
Expected dividend yield	3.6% - 4.3%	2.7% - 3.8%	2.5% – 3.0%
Weighted-average expected dividend yield	3.8%	2.7%	2.9%
Expected volatility	20.9% - 21.9%	17.8% - 20.9%	17.2% – 17.5%
Weighted-average volatility	20.9%	17.9%	17.4%

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 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 length of the option's expected term for 2018. The volatility period used was 68 months, 68 months and 71 months at December 31, 2018, 2017 and 2016, respectively.

The following is a summary of the status of stock options:

	Stock options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (in millions)
Outstanding at December 31, 2017	4,445,702	$ 56.46		
Granted	960,240	60.86		
Forfeited or expired	(125,260)	68.90		
Exercised[1]	(288,302)	41.57		
Transfers, net	44,805	55.74		
Outstanding at December 31, 2018	5,037,185	57.84	5.79	
Vested and expected to vest at December 31, 2018	4,982,445	57.77	5.75	$ 25
Exercisable at December 31, 2018	3,089,466	$ 52.15	4.33	$ 25

1 SCE recognized tax benefits of $2 million from stock options exercised in 2018.

At December 31, 2018, total unrecognized compensation cost related to stock options and the weighted-average period the cost is expected to be recognized are as follows:

(in millions)	
Unrecognized compensation cost, net of expected forfeitures	$ 8
Weighted-average period (in years)	2.2

Supplemental Data on Stock Options

(in millions, except per award amounts)	Years ended December 31, 2018	2017	2016
Stock options:			
Weighted average grant date fair value per option granted	$ 8.22	$ 10.63	$ 7.50
Fair value of options vested	7	5	5
Value of options exercised	7	29	41

Performance Shares

A target number of contingent performance shares were awarded to executives in March 2018, 2017 and 2016 and vest at December 31, 2020, 2019 and 2018, respectively. The vesting of the grants is dependent upon market and financial performance and service conditions as defined in the grants for each of the years. The number of performance shares earned from each year's grants could range from zero to twice the target number (plus additional units credited as dividend equivalents). Performance shares that were granted during 2016 to 2018 are settled solely in cash and are classified as a share-based liability award. Performance shares awarded, beginning in 2019, will be settled in common stock and will be classified as share-based equity awards. The fair value of these shares granted during 2016 to 2018 is re-measured at each reporting period, and the related compensation expense is adjusted. Performance shares expense is recognized ratably over the requisite service period based on the fair values determined (subject to the adjustments discussed above), except for awards granted to retirement-eligible participants.

The fair value of market condition performance shares is determined using a Monte Carlo simulation valuation model for the total shareholder return. The fair value of financial performance condition performance shares is determined using Edison International's earnings per share compared to pre-established targets.

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

	Shares	Weighted-Average Fair Value
Nonvested at December 31, 2017	88,722	$ 64.01
Granted	64,335	
Forfeited	(27,331)	
Vested[1]	(24,574)	
Affiliate transfers, net	706	
Nonvested at December 31, 2018	101,858	42.96

1 Relates to performance shares that will be paid in 2019 as performance targets were met at December 31, 2018.

Restricted Stock Units

Restricted stock units were awarded to executives in March 2018, 2017 and 2016 and vest and become payable on January 4, 2021, January 2, 2020 and January 2, 2019, respectively. Each restricted stock unit awarded includes a dividend equivalent feature and is a contractual right to receive one share of Edison International common stock, if vesting requirements are satisfied. The vesting of restricted stock units is dependent upon continuous service through the end of the vesting period, except for awards granted to retirement-eligible participants.

The following is a summary of the status of nonvested restricted stock units:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2017	141,418	$ 69.96
Granted	64,919	60.87
Forfeited	(7,973)	68.97
Vested	(51,667)	64.07
Affiliate transfers, net	1,129	68.64
Nonvested at December 31, 2018	147,826	68.08

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

Investments

Nuclear Decommissioning Trusts

Future decommissioning costs related to SCE's nuclear assets are expected to be funded from independent decommissioning trusts.

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

		Amortized Cost		Fair Value	
	Longest	December 31,			
(in millions)	Maturity Date	2018	2017	2018	2017
Stocks	—	*	$ 236	$ 1,381	$ 1,596
Municipal bonds	2057	665	643	767	768
U.S. government and agency securities	2067	1,193	1,235	1,288	1,319
Corporate bonds	2050	573	579	611	643
Short-term investments and receivables/payables[1]	One-year	70	110	73	114
Total		$ 2,501	$ 2,803	$ 4,120	$ 4,440

* Effective January 1, 2018, SCE adopted an accounting standards update related to the classification and measurement of financial instruments in which equity investments are measured at fair value.

1 Short-term investments include $71 million and $29 million of repurchase agreements payable by financial institutions which earn interest, are fully secured by U.S. Treasury securities and mature by January 2, 2019 and January 2, 2018 as of December 31, 2018 and 2017, respectively.

Trust fund earnings (based on specific identification) increase the trust fund balance and the ARO regulatory liability. Unrealized holding gains, net of losses, were $1.4 billion and $1.6 billion at December 31, 2018 and 2017, respectively, and other-than-temporary impairments of $170 million and $143 million at the respective periods.

Trust assets are used to pay income taxes. Deferred tax liabilities related to net unrealized gains at December 31, 2018 were $323 million. Accordingly, the fair value of trust assets available to pay future decommissioning costs, net of deferred income taxes, totaled

$3.8 billion at December 31, 2018.

The following table summarizes the gains and (losses) for the trust investments:

	December 31,		
(in millions)	2018	2017	2016
Gross realized gains	$ 134	$ 244	$ 92
Gross realized losses	(27)	(23)	(19)
Net unrealized (losses) gains for equity securities	(233)	142	75

Due to regulatory mechanisms, changes in assets of the trusts from income or loss items have no impact on operating revenue or earnings.

Regulatory Assets and Liabilities

Included in SCE's regulatory assets and liabilities are regulatory balancing accounts. CPUC authorized balancing account mechanisms require SCE to refund or recover any differences between forecasted and actual costs. The CPUC has authorized balancing accounts for specified costs or programs such as fuel, purchased-power, demand-side management programs, nuclear decommissioning and public purpose programs. Certain of these balancing accounts include a return on rate base of 7.61% and 7.90% in 2018 and 2017, respectively. The CPUC authorizes the use of a balancing account to recover from or refund to customers differences in revenue resulting from actual and forecasted electricity sales.

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 power contracts primarily represent derivative contracts that were designated as normal purchase and normal sale contracts. The liabilities for these power contracts are amortized over the remaining contract terms, approximately 2 to 5 years. SCE's regulatory assets related to deferred income taxes represent tax benefits passed through to customers. The CPUC requires SCE to flow through certain deferred income tax benefits to customers by reducing electricity rates, thereby deferring recovery of such amounts to future periods. Based on current regulatory ratemaking and income tax laws, SCE expects to recover its regulatory assets related to deferred income taxes over the life of the assets that give rise to the accumulated deferred income taxes, approximately from 1 to 60 years. As a result of Tax Reform, SCE re-measured its deferred tax assets and liabilities as of December 31, 2017. SCE's regulatory assets related to pensions and other post-retirement plans represent the unfunded net loss and prior service costs of the plans. This amount is being recovered through rates charged to customers.

SCE has long-term unamortized investments which include nuclear assets related to Palo Verde and the beyond the meter program. Nuclear assets related to Palo Verde and the beyond the meter program are expected to be recovered by 2047 and 2027, respectively, and both earned returns of 7.61% in 2018 and 7.90% in 2017.

SCE's net regulatory asset related to its unamortized loss on reacquired debt will be recovered over the original amortization period of the reacquired debt over periods ranging from 10 to 35 years or the life of the new issue if the debt is refunded or refinanced.

SCE's regulatory assets related to environmental remediation represents a portion of the costs incurred at certain sites that SCE is allowed to recover through customer rates.

Regulatory Liabilities

SCE's regulatory liabilities related to energy derivatives are primarily an offset to unrealized gains on derivatives.

SCE's regulatory liabilities related to costs of removal represent differences between asset removal costs recorded and amounts collected in rates for those costs.

As a result of Tax Reform, SCE's deferred tax assets and liabilities were re-measured at December 31, 2017 resulting in an increase in regulatory liabilities which is subject to change based on the outcome of the regulatory process. The regulatory liabilities are generally expected to be refunded to customers over the lives of the assets and liabilities that gave rise to the deferred taxes. SCE's regulatory liabilities related to recoveries in excess of ARO liabilities represents the cumulative differences between ARO expenses and amounts collected in rates primarily for the decommissioning of the SCE's nuclear generation facilities. Decommissioning costs recovered through rates are primarily placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses on the nuclear decommissioning trust investments.

Net Regulatory Balancing Accounts

Balancing accounts track amounts that the CPUC or FERC have authorized for recovery. Balancing account over and under collections represent differences between cash collected in current rates for specified forecasted costs and such costs that are actually incurred. Undercollections are recorded as regulatory balancing account assets. Overcollections are recorded as regulatory balancing account liabilities. With some exceptions, SCE seeks to adjust rates on an annual basis or at other designated times to recover or refund the balances recorded in its balancing accounts. Memorandum accounts are authorized to track costs for potential future recovery.

Regulatory balancing and memorandum accounts that SCE does not expect to collect or refund in the next 12 months are reflected in the long-term section of the consolidated balance sheets. Regulatory balancing and memorandum accounts that do not have the right of offset are presented gross in the consolidated balance sheets. Under and over collections in balancing accounts and amounts recorded in memorandum accounts typically accrue interest based on a three-month commercial paper rate published by the Federal Reserve.

Commitments

Power Purchase Agreements

SCE entered into various agreements to purchase power, electric capacity and other energy products. At December 31, 2018, the undiscounted future expected minimum payments for the SCE PPAs (primarily related to renewable energy contracts), which were approved by the CPUC and met other critical contract provisions (including completion of major milestones for construction), were as follows:

(in millions)	Total
2019	$ 2,562
2020	2,602
2021	2,570
2022	2,415
2023	2,185
Thereafter	23,855
Total future commitments	$ 36,189

Additionally, SCE has executed contracts (including capacity reduction contracts) that have not met the critical contract provisions that would increase contractual obligations by $66 million in 2019, $176 million in 2020, $189 million in 2021, $184 million in 2022, $183 million in 2023 and $2.2 billion thereafter, if all critical contract provisions are completed.

Costs incurred for PPAs were $3.8 billion in 2018, $3.6 billion in 2017 and $3.3 billion in 2016, which include costs associated with contracts with terms of less than one year.

Certain PPAs that SCE entered into may be accounted for as leases. The following table shows the future minimum lease payments due under the contracts that are treated as operating and capital leases (these amounts are also included in the table above). Due to the inherent uncertainty associated with the reliability of the fuel source, expected purchases from most renewable energy contracts do not meet the definition of a minimum lease payment and have been excluded from the operating and capital lease table below but remain in the table above. The future minimum lease 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
2019	$ 148	$ 5
2020	124	6
2021	103	6
2022	79	6
2023	47	5
Thereafter	536	66
Total future commitments	$ 1,037	$ 94
Amount representing executory costs		(25)
Amount representing interest		(33)
Net commitments[1]		$ 36

1 Includes two contracts with net commitments of $26 million that will commence in 2019.

In 2018, SCE amended the termination date of two power purchase agreements, which are classified as operating leases. As a result of this amendment, future minimum payments for these operating leases, totaling $986 million, were removed from the table above. SCE is required to make early termination payments of $100 million in 2019, $77 million in 2020 and $29 million in 2021, which were included in the consolidated balance sheets as of December 31, 2018.

Operating lease expense for PPAs was $2.3 billion in 2018, and $2.3 billion in 2017 and $1.9 billion in 2016 (including contingent rents of $2.1 billion in 2018, $1.8 billion in 2017 and $1.4 billion in 2016). Contingent rents for capital leases were $104 million in 2018, $99 million in 2017 and $109 million in 2016. The timing of SCE's recognition of the lease expense conforms to ratemaking treatment for SCE's recovery of the cost of electricity and is included in purchased power.

Other Lease Commitments

The following summarizes the estimated minimum future commitments for SCE’s non-cancelable other operating leases (primarily related to vehicles, office space and other equipment):

(in millions)	Total
2019	$ 42
2020	31
2021	27
2022	22
2023	17
Thereafter	101
Total future commitments	$ 240

Operating lease expense for other leases were $57 million in 2018, $59 million in 2017 and $68 million in 2016. Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rentals payable under these leases may increase by a fixed amount each year, a percentage over base year, or the consumer price index.

Other Commitments

The following summarizes the estimated minimum future commitments for SCE's other commitments:

(in millions)	2019	2020	2021	2022	2023	Thereafter	Total
Other contractual obligations	$ 79	$ 67	$ 46	$ 44	$ 35	$ 209	$ 480

Costs incurred for other commitments were $124 million in 2018, $75 million in 2017 and $141 million in 2016. SCE has fuel supply contracts for Palo Verde which require payment only if the fuel is made available for purchase. SCE also has commitments related to maintaining reliability and expanding SCE's transmission and distribution system.

The table above does not include asset retirement obligations.

Indemnities

SCE has various financial and performance guarantees and indemnity agreements which are issued in the normal course of business.

SCE has agreed to provide 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 indemnities for specified environmental liabilities and income taxes with respect to assets sold. SCE's obligations under these agreements may or may not be limited in terms of time and/or amount, and in some instances SCE may have recourse against third parties. SCE has not recorded a liability related to these indemnities. The overall maximum amount of the obligations under these indemnifications cannot be reasonably estimated.

SCE has agreed to indemnify the City of Redlands, California in connection with the Mountainview power plant's California Energy Commission permit 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. As of December 31, 2018, there has been no groundwater contamination identified. Thus, SCE has not recorded a liability related to this indemnity.

Preferred and Preference Stock of Utility

SCE's authorized shares are: $100 cumulative preferred – 12 million shares, $25 cumulative preferred – 24 million shares and preference with no par value – 50 million shares. SCE's outstanding shares are not subject to mandatory redemption. There are no dividends in arrears for the preferred or preference shares. Shares of SCE's preferred stock have liquidation and dividend preferences over shares of SCE's common stock and preference stock. All cumulative preferred shares are redeemable. When preferred shares are redeemed, the premiums paid, if any, are charged to common equity. No preferred shares were issued or redeemed in the years ended December 31, 2018, 2017 and 2016. There is no sinking fund requirement for redemptions or repurchases of preferred shares.

Shares of SCE's preference stock rank junior to all of the preferred stock and senior to all common stock. Shares of SCE's preference stock are not convertible into shares of any other class or series of SCE's capital stock or any other security. There is no sinking fund requirement for redemptions or repurchases of preference shares.

Shares of Series E preference stock issued in 2012 may be redeemed at par, in whole or in part, on or after February 1, 2022. Shares of Series G, H, J, K and L preference stock, issued in 2013, 2014, 2015, 2016 and 2017, respectively, may be redeemed at par, in whole, but not in part, at any time prior to March 15, 2018, March 15, 2024, September 15, 2025, March 15, 2026 and June 26, 2022, respectively, if certain changes in tax or investment company law or interpretation (or applicable rating agency equity credit criteria for Series L only) occur and certain other conditions are satisfied. On or after March 15, 2018, March 15, 2024, September 15, 2025, March 15, 2026 and June 26, 2022, SCE may redeem the Series G, H, J, K and L shares, respectively, at par, in whole or in part. For shares of Series H, J and K preference stock, distributions will accrue and be payable at a floating rate from and including March 15, 2024, September 15, 2025 and March 15, 2026, respectively. Shares of Series G, H, J, K and L preference stock were issued to SCE Trust II, SCE Trust III, SCE Trust IV, SCE Trust V and SCE Trust VI, respectively, special purpose entities formed to issue trust securities.

Supplemental Cash Flows Information

Supplemental cash flows information is:

(in millions)	Years ended December 31, 2018	2017	2016
Cash payments (receipts) for interest and taxes:			
Interest, net of amounts capitalized	$ 552	$ 509	$ 475
Tax (refunds) payments, net	(57)	2	78
Non-cash financing and investing activities:			
Dividends declared but not paid:			
Common stock	$ —	$ 212	$ —
Preferred and preference stock	12	12	12

SCE's accrued capital expenditures at December 31, 2018, 2017 and 2016 were $594 million, $652 million, and $540 million, respectively. Accrued capital expenditures will be included as an investing activity in the consolidated statements of cash flow in the period paid.

Related-Party Transactions

SCE provides and receives various services to and from its subsidiaries and affiliates. Services provided to Edison International by SCE are priced at fully loaded cost (i.e., direct cost of good or service and allocation of overhead cost). Specified administrative services such as payroll, employee benefit programs, all performed by Edison International or SCE employees, are shared among all affiliates of Edison International. Costs are allocated based on one of the following formulas: percentage of time worked, equity in investment and advances, number of employees, or multi-factor (operating revenue, operating expenses, total assets and number of employees). Edison International allocates various corporate administrative and general costs to SCE and other subsidiaries using established allocation factors.

For the years ended December 31, 2018 and 2017, SCE purchased wildfire liability insurance for premiums of $22 million and $144 million, respectively, from Edison Insurance Services, Inc. ("EIS"), a wholly-owned subsidiary of Edison International. EIS fully reinsured the exposure for these policies through the commercial reinsurance market, with reinsurance limits and premiums equal to those of the insurance purchased by SCE. The related-party transactions included in SCE's consolidated balance sheets for wildfire-related insurance purchased from EIS were as follows:

	December 31,	
(in millions)	2018	2017
Long-term insurance receivable due from affiliate	$ 1,000	$ —
Prepaid insurance[1]	13	131
Current payables due to affiliate	4	3

1 The amortization expense for prepaid insurance was $140 million and $13 million for the years ended December 31, 2018 and 2017, respectively.

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, individually or in the aggregate, materially affect its financial position, results of operations and cash flows.

Southern California Wildfires and Mudslides

Approximately 35% of SCE's service territory is in areas identified as high fire risk by SCE. Multiple factors have contributed to increased wildfires, faster progression of wildfires and the increased damage from wildfires across SCE's service territory and throughout California. These include the buildup of dry vegetation in areas severely impacted by years of historic drought, lack of adequate clearing of hazardous fuels by responsible parties, higher temperatures, lower humidity, and strong Santa Ana winds. At the same time that wildfire risk has been increasing in Southern California, residential and commercial development has occurred and is occurring in some of the highest-risk areas. Such factors can increase the likelihood and extent of wildfires.

In December 2017 and November 2018, wind-driven wildfires impacted portions of SCE's service territory, causing substantial damage to both residential and business properties and service outages for SCE customers. The largest of the 2017 fires, known as the Thomas Fire, originated in Ventura County and burned acreage located in both Ventura and Santa Barbara Counties. The largest of the 2018 fires, known as the Woolsey Fire, originated in Ventura County and burned acreage in both Ventura and Los Angeles Counties. According to California Department of Forestry and Fire Protection ("CAL FIRE") information, the Thomas Fire burned over 280,000 acres, destroyed an estimated 1,063 structures, damaged an estimated 280 structures and resulted in two fatalities, while the Woolsey Fire burned almost 100,000 acres, destroyed an estimated 1,643 structures, damaged an estimated 364 structures and resulted in three fatalities. As of December 31, 2018, SCE had incurred approximately $89 million of capital expenditures related to restoration of service resulting from the Thomas Fire and the Montecito Mudslides (as defined below) and $82 million resulting from the Woolsey Fire.

As described below, multiple lawsuits related to the Thomas Fire and the Woolsey Fire have been initiated against SCE and Edison International. Some of the Thomas Fire-related lawsuits claim that SCE and Edison International have responsibility for the damages caused by mudslides and flooding in Montecito and surrounding areas in January 2018 (the "Montecito Mudslides") based on a theory that SCE has responsibility for the Thomas Fire and that the Thomas Fire proximately caused the Montecito Mudslides. According to Santa Barbara County initial reports, the Montecito Mudslides destroyed an estimated 135 structures, damaged an estimated 324 structures, and resulted in 21 fatalities, with two additional fatalities presumed.

The extent of liability for wildfire-related damages in actions against utilities depends on a number of factors, including whether SCE substantially caused or contributed to the damages and whether parties seeking recovery of damages will be required to show negligence in addition to causation. California courts have previously found utilities to be strictly liable for property damage along with associated interest and attorneys' fees, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. If inverse condemnation is held to be inapplicable to SCE in connection with a wildfire, SCE still could be held liable for property damages and associated interest if the property damages were found to have been proximately caused by SCE's negligence. If SCE were to be found negligent, SCE could also be held liable for, among other things, fire suppression costs, business interruption losses, evacuation costs, clean-up costs, medical expenses, and personal injury/wrongful death claims. Additionally, SCE could potentially be subject to fines for alleged violations of CPUC rules and state laws in connection with the ignition of a wildfire.

Investigations into the causes of the Thomas Fire, the Montecito Mudslides and the Woolsey Fire (collectively, the "2017/2018 Wildfire/Mudslide Events") are ongoing and final determinations of liability, including determinations of whether SCE was negligent, would only be made during lengthy and complex litigation processes. Even when investigations are still pending or liability is disputed, an assessment of likely outcomes, including through future settlement of disputed claims, may require a charge to be accrued under accounting standards. Based on SCE's internal review into the facts and circumstances of each of the 2017/2018 Wildfire/Mudslide Events and consideration of the risks associated with litigation, SCE expects to incur a material loss in connection with the 2017/2018 Wildfire/Mudslide Events and have accrued a charge, before recoveries and taxes, of $4.7 billion in the fourth quarter of 2018. SCE also recorded expected recoveries from insurance of $2.0 billion and expected recoveries through FERC electric rates of $135 million. The net charge to earnings recorded was $1.8 billion after-tax. This charge corresponds to the lower end of the reasonably estimated range of expected potential losses that may be incurred in connection with the 2017/2018 Wildfire/Mudslide Events and is subject to change as additional information becomes available. SCE will seek to offset any actual losses realized with recoveries from insurance policies in place at the time of the events and, to the extent actual losses exceed insurance, through electric rates. The CPUC and FERC may not allow SCE to recover uninsured losses through electric rates if it is determined that such losses were not reasonably or prudently incurred. See "—Loss Estimates for Third Party Claims and Potential Recoveries from Insurance and through Electric Rates" for additional information.

Internal Review

Thomas Fire

SCE's internal review into the facts and circumstances of the Thomas Fire is complex and examines various matters including possible ignition points, the location of those ignition points, fire progression and the attribution of damages to fires with separate ignition points. SCE expects to obtain and review additional information and materials in the possession of CAL FIRE and others during the course of its internal review and the Thomas Fire litigation process.

Based on currently available information, SCE believes that the Thomas Fire had at least two separate ignition points, one near Koenigstein Road in the City of Santa Paula and the other in the Anlauf Canyon area of Ventura County. With respect to the Koenigstein Road ignition point, witnesses have reported that a fire ignited in the vicinity of an SCE power pole and SCE later learned of a downed electrical wire at this location. SCE believes that its equipment was associated with this ignition. SCE is continuing to assess the progression of the fire from the Koenigstein Road ignition point and the extent of damages that may be attributable to that ignition. At this time, based on available information, SCE has not determined whether the ignition in the Anlauf Canyon area involved SCE equipment.

Montecito Mudslides

SCE's internal review also includes inquiry into whether the Thomas Fire proximately caused or contributed to the Montecito

Mudslides, the source of ignition of the portion of the Thomas Fire that burned through the Montecito area and other factors that potentially contributed to the losses that resulted from the Montecito Mudslides. Many other factors, including, but not limited to, weather conditions and insufficiently or improperly designed and maintained debris basins, roads, bridges and other channel crossings, could have proximately caused, contributed to or exacerbated the losses that resulted from the Montecito Mudslides. At this time, based on available information, SCE has not been able to determine the source of ignition of the portion of the Thomas Fire that burned within the Montecito area. In the event that SCE is determined to have caused the fire that spread to the Montecito area, SCE cannot predict whether, if fully litigated, the courts would conclude that the Montecito Mudslides were caused or contributed to by the Thomas Fire or that SCE would be liable for some or all of the damages caused by the Montecito Mudslides.

Woolsey Fire

SCE's internal review into the facts and circumstances of the Woolsey Fire is ongoing. SCE has reported to the CPUC that there was an outage on SCE's electric system in the vicinity of where the Woolsey Fire reportedly began on November 8, 2018. SCE is aware of witnesses who saw fire in the vicinity of SCE's equipment at the time the fire was first reported. While SCE did not find evidence of downed electrical wires on the ground in the suspected area of origin, it observed a pole support wire in proximity to an electrical wire that was energized prior to the outage. Whether the November 8, 2018 outage was related to contact being made between the support wire and the electrical wire has not been determined. SCE believes that its equipment could be found to have been associated with the ignition of the Woolsey Fire. SCE expects to obtain and review additional information and materials in the possession of CAL FIRE and others during the course of its internal review and the Woolsey Fire litigation process, including SCE equipment that has been retained by CAL FIRE.

External Investigations

CAL FIRE and Ventura County Fire Department ("VCFD") issued a report on March 13, 2019 on their review of the causes of the fire that originated at the Anlauf Canyon ignition point. The report alleges that SCE's equipment was involved in the Anlauf Canyon ignition point. CAL FIRE and VCFD also issued a report on March 20, 2019 on their review of the causes of the fire that originated near Koenigstein Road. VCFD and CAL FIRE found that SCE equipment contributed to the ignition near Koenigstein Road. The reports did not address the causes of the Montecito Mudslides.

Based on currently available information, SCE has not determined whether its equipment caused the ignition in the Anlauf Canyon area. SCE provided evidence to CAL FIRE and VCFD that indicates the ignition at Anlauf Canyon started at least 12 minutes prior to any issue involving SCE's system and at least 15 minutes prior to the start time indicated by VCFD in its report. Final determinations of liability for both fires would only be made during lengthy and complex litigation processes.

The CPUC's Safety Enforcement Division ("SED") is also conducting investigations to assess SCE's compliance with applicable rules and regulations in areas impacted by the fires. SCE cannot predict when the investigations of CAL FIRE, VCFD or SED will be completed.

Wildfire-related Litigation

Multiple lawsuits related to the 2017/2018 Wildfire/Mudslide Events naming SCE as a defendant have been filed. A number of the lawsuits also name Edison International as a defendant and some of the lawsuits were filed as purported class actions. The lawsuits, which have been filed in the superior courts of Ventura, Santa Barbara and Los Angeles Counties in the case of the Thomas Fire and the Montecito Mudslides, and in Ventura and Los Angeles Counties in the case of the Woolsey Fire, allege, among other things, negligence, inverse condemnation, trespass, private nuisance, personal injury, wrongful death, and violations of the California Public Utilities and Health and Safety Codes. SCE expects to be the subject of additional lawsuits related to the 2017/2018 Wildfire/Mudslide Events. The litigation could take a number of years to be resolved because of the complexity of the matters and number of plaintiffs.

The Thomas Fire and Montecito Mudslides lawsuits are being coordinated in the Los Angeles Superior Court. The Woolsey Fire lawsuits have also been recommended for coordination in the Los Angeles Superior Court. On October 4, 2018, the Superior Court denied Edison International's and SCE's challenge to the application of inverse condemnation to SCE with respect to the Thomas Fire and, on February 26, 2019, the California Supreme Court denied SCE's petition to review the Superior Court's decision. In January 2019, SCE filed a cross-complaint against certain governmental entities alleging that failures by these entities, such as failure to adequately plan for flood hazards and build and maintain adequate debris basins, roads, bridges and other channel crossings, among other things, caused, contributed to or exacerbated the losses that resulted from the Montecito Mudslides.

Additionally, in July 2018 and September 2018, two separate derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the Los Angeles Superior Court against certain current and former members of the Boards of Directors of Edison International and SCE. Edison International and SCE are identified as nominal defendants in those actions. The derivative lawsuits generally allege that the individual defendants violated their fiduciary duties by causing or allowing SCE to operate in an unsafe manner in violation of relevant regulations, resulting in substantial liability and damage from the Thomas Fire and the Montecito Mudslides.

In November 2018, a purported class action lawsuit alleging securities fraud and related claims was filed in the federal court against certain current and former officers of Edison International and SCE. The plaintiff alleges that Edison International and SCE made false and/or misleading statements in filings with the Securities and Exchange Commission by failing to disclose that SCE had allegedly failed to maintain its electric transmission and distribution networks in compliance with safety regulations, and that those alleged safety violations led to fires that occurred in 2018, including the Woolsey Fire.

In January 2019, two separate derivative lawsuits alleging breach of fiduciary duties, securities fraud, misleading proxy statements, unjust enrichment, and related claims were filed in federal court against all current and certain former members of the board of directors and certain current and former officers of Edison International and SCE. Edison International and SCE are named as nominal defendants in those actions. The derivative lawsuits generally allege that the individual defendants breached their fiduciary duties and made misleading statements or allowed misleading statements to be made (i) between March 21, 2014 and August 10, 2015, with respect to certain ex parte communications between SCE and CPUC decision-makers concerning the settlement of the San Onofre Order Instituting Investigation proceeding (the "San Onofre OII") and (ii) from February 23, 2016 to the present, concerning compliance with applicable laws and regulations concerning electric system maintenance and operations related to wildfire risks. The lawsuits generally allege that these breaches of duty and misstatements led to substantial liability and damage resulting from the disclosure of SCE's ex parte communications in connection with the San Onofre OII settlement, and from the 2017/2018 Wildfire/Mudslide Events. For more information regarding the San Onofre OII, see "—Permanent Retirement of San Onofre" below.

Loss Estimates for Third Party Claims and Potential Recoveries from Insurance and through Electric Rates

The process for estimating losses associated with wildfire litigation claims requires management to exercise significant judgment based on a number of assumptions and subjective factors, including but not limited to estimates based on currently available information and assessments, opinions regarding litigation risk, and prior experience with litigating and settling other wildfire cases. As additional information becomes available, management estimates and assumptions regarding the causes and financial impact of the 2017/2018 Wildfire/Mudslide Events may change. Such additional information is expected to become available from multiple external sources, during the course of litigation, and from SCE's ongoing internal review, including, among other things, information regarding the extent of damages that may be attributable to any ignition determined to have been substantially caused by SCE's equipment, information that may be obtained from the equipment in CAL FIRE's possession, and information pertaining to fire progression, suppression activities, alleged damages and insurance claims.

As described above, the $1.8 billion after-tax charge corresponds to the lower end of the reasonably estimated range of expected losses that may be incurred in connection with the 2017/2018 Wildfire/Mudslide Events and is subject to change as additional information becomes available. SCE currently believes that it is reasonably possible that the amount of the actual loss will be greater than the amount accrued. However, SCE is currently unable to reasonably estimate an upper end of the range of expected losses given the uncertainty as to the legal and factual determinations to be made during litigation, including uncertainty as to the contributing causes of the 2017/2018 Wildfire/Mudslide Events, the complexities associated with multiple ignition points, the potential for separate damages to be attributable to fires ignited at separate ignition points, whether inverse condemnation will be held applicable to SCE with respect to damages caused by the Montecito Mudslides, and the preliminary nature of the litigation processes.

For events that occurred in 2017 and early 2018, principally the Thomas Fire and Montecito Mudslides, SCE has $1 billion of wildfire-specific insurance coverage, subject to a self-insured retention of $10 million per occurrence. SCE also had other general liability insurance coverage of approximately $450 million, but it is uncertain whether these other policies would apply to liabilities alleged to be related to the Montecito Mudslides. For the Woolsey Fire, SCE has an additional $1 billion of wildfire-specific insurance coverage, subject to a self-insured retention of $10 million per occurrence. SCE records a receivable for insurance recoveries when recovery of a recorded loss is determined to be probable. At December 31, 2018, SCE had recorded $2.0 billion for expected insurance recoveries associated with the recorded loss for the 2017/2018 Wildfire/Mudslide Events. The amount of the receivable is subject to change based on additional information.

SCE will seek to recover uninsured costs resulting from the 2017/2018 Wildfire/Mudslide Events through electric rates. Recovery of these costs is subject to approval by regulators. Under accounting standards for rate-regulated enterprises, SCE defers costs as regulatory assets when it concludes that such costs are probable of future recovery in electric rates. SCE utilizes objectively determinable evidence to form its view on probability of future recovery. The only directly comparable precedent in which a California investor-owned utility has sought recovery for uninsured wildfire-related costs is SDG&E’s requests for cost recovery related to 2007 wildfire activity, where FERC allowed recovery of all FERC-jurisdictional wildfire-related costs while the CPUC rejected recovery of all CPUC-jurisdictional wildfire-related costs based on a determination that SDG&E did not meet the CPUC’s prudency standard. As a result, while SCE does not agree with the CPUC’s decision, it believes that the CPUC’s interpretation and application of the prudency standard to SDG&E creates substantial uncertainty regarding how that standard will be applied to an investor-owned utility in future wildfire cost-recovery proceedings. SCE will continue to evaluate the probability of recovery based on available evidence, including guidance that may be issued by the commission on Catastrophic Wildfire Cost and Recovery, and new judicial, legislative and regulatory decisions, including any CPUC decisions illustrating the interpretation and/or application of the prudency standard when making determinations regarding recovery of uninsured wildfire-related costs. While the CPUC has not made a determination regarding SCE's prudency relative to any of the 2017/2018 Wildfire/Mudslide Events, SCE is unable to conclude, at this time, that uninsured CPUC-jurisdictional wildfire-related costs are probable of recovery through electric rates. SCE would record a regulatory asset at the time it obtains sufficient information to support a conclusion that recovery is probable. SCE will seek recovery of the CPUC portion of any uninsured wildfire-related costs through its WEMA. See "—Recovery of Wildfire-Related Costs" below.

Through the operation of its FERC Formula Rate, and based upon the precedent established in SDG&E's recovery of FERC-jurisdictional wildfire-related costs, SCE believes it is probable it will recover its FERC-jurisdictional wildfire and mudslide related costs and has recorded a regulatory asset of $135 million, the FERC portion of the $4.7 billion charge accrued.

At December 31, 2018, the balance sheets include estimated losses (established at the lower end of the reasonably estimated range of expected losses) of $4.7 billion for the 2017/2018 Wildfire/Mudslide Events. For the year-ended December 31, 2018, the income statements include the estimated losses (established at the lower end of the reasonably estimated range of expected losses), net of expected recoveries from insurance and FERC customers, related to the 2017/2018 Wildfire/Mudslide Events as follows:

(in millions)	Year ended December 31, 2018
Charge for wildfire-related claims	$ 4,669

Expected insurance recoveries		(2,000)
Expected revenue from FERC customers		(135)
Total pre-tax charge		2,534
Income tax benefit		(709)
Total after-tax charge	$	1,825

Waiver of CPUC Equity Ratio Requirement

Under SCE's interpretation of the CPUC's capital structure decisions, SCE is required to maintain a 48% equity ratio on average over a 37-month period and to file an application for a waiver to the capital structure condition if an adverse financial event reduces its spot equity ratio below 47%. On February 28, 2019, SCE submitted an application to the CPUC for waiver of compliance with this equity ratio requirement, describing that while the charge accrued in connection with the 2017/2018 Wildfire/Mudslide Events caused its equity ratio to fall below 47% on a spot basis as of December 31, 2018, SCE remains in compliance with the 48% equity ratio over the applicable 37-month average basis. In its application, SCE is seeking a limited waiver to exclude wildfire-related charges and wildfire-related debt issuances from its equity ratio calculations until a determination regarding cost recovery is made. Under the CPUC's rules, SCE will not be deemed to be in violation of the equity ratio requirement, and therefore may continue to issue debt and dividends, while the waiver application is pending resolution.

Current Wildfire Insurance Coverage

SCE has approximately $1 billion of wildfire-specific insurance coverage, subject to a self-insured retention of $10 million per occurrence, for events (including the Woolsey fire) during the period June 30, 2018 through May 31, 2019. If the $1 billion of insurance coverage is exhausted as a result of liabilities related to the Woolsey Fire, SCE has approximately $700 million of wildfire-specific insurance coverage for wildfire events during the period February 1, 2019 through May 31, 2019, subject to a self-insured retention of $10 million per occurrence and up to $15 million of co-insurance. SCE has also obtained $750 million of wildfire-specific insurance coverage for events that may occur during the period June 1, 2019 through June 30, 2020, subject to a self-insured retention of $10 million per occurrence and up to $115 million of co-insurance. SCE may obtain additional wildfire-specific insurance for this time period in the future. Various coverage limitations within the policies that make up SCE's wildfire insurance coverage could result in material self-insured costs in the event of multiple wildfire occurrences during a policy period or with a single wildfire with damages in excess of the policy limits.

SCE's cost of obtaining wildfire insurance coverage has increased significantly as a result of, among other things, the number of recent and significant wildfire events throughout California and the application of inverse condemnation to investor-owned utilities. As such, SCE may not be able to obtain sufficient wildfire insurance at a reasonable cost.

SCE's wildfire insurance expense, prior to any regulatory deferrals, totaled approximately $237 million during 2018. Based on policies currently in effect, SCE anticipates that its wildfire insurance expense, prior to any regulatory deferrals, will total approximately $321 million during 2019. Wildfire insurance expense will increase in 2019 if SCE obtains additional wildfire-specific insurance. As of December 31, 2018, SCE had a regulatory asset of $128 million related to wildfire insurance costs and believes that such amounts are probable of recovery. While SCE believes that amounts deferred are probable of recovery, there is no assurance that SCE will be allowed to recover costs that have been incurred, or costs incurred in the future for additional wildfire insurance, in electric rates. In February 2019, the CPUC approved recovery of $107 million of the costs incurred by SCE to obtain a 12-month, $300 million wildfire insurance policy in December 2017. As a result of this decision, SCE will recover these insurance premiums during 2019.

Recovery of Wildfire-Related Costs

California courts have previously found investor-owned utilities to be strictly liable for property damage, regardless of fault, by applying the theory of inverse condemnation when a utility's facilities were determined to be a substantial cause of a wildfire that caused the property damage. The rationale stated by these courts for applying this theory to investor-owned utilities is that property damages resulting from a public improvement, such as the distribution of electricity, can be spread across the larger community that benefited from such improvement through recovery of uninsured wildfire-related costs in electric rates. However, in November 2017, the CPUC issued a decision denying SDG&E's request to include in its rates uninsured wildfire-related costs arising from several 2007 fires, finding that SDG&E did not prudently manage and operate its facilities prior to or at the outset of the 2007 wildfires. In July 2018, the CPUC denied both SDG&E's application for rehearing on its cost recovery request and a joint application for rehearing filed by SCE and PG&E limited to the applicability of inverse condemnation principles in the same proceeding. The California Court of Appeal denied SDG&E’s petition for review of the CPUC's denial of SDG&E's application and the California Supreme Court denied SDG&E’s petition to review the Court of Appeal’s denial of SDG&E's petition to review.

In September 2018, California Senate Bill 901 ("SB 901") was signed by the Governor of California. Although SB 901 does not address the strict liability standard imposed by courts in inverse condemnation actions, the bill as enacted introduces a number of considerations the CPUC can apply to determine whether costs are recoverable in electric rates for wildfires occurring on or after January 1, 2019, including, among other things, the utility's actions, circumstances beyond the utility's control and the impact of extreme climate conditions. SB 901 requires investor-owned utilities to prepare annually, for CPUC approval, wildfire risk mitigation plans, and, compliance with an approved plan is one factor the CPUC can consider in addressing cost recovery. On February 6, 2019, in compliance with SB 901, SCE filed its wildfire mitigation plan for 2019. While SCE takes the position, in its wildfire mitigation plan, that substantial compliance with the plan, once approved, will demonstrate that SCE prudently operated its system and met the CPUC’s prudent manager standard regarding wildfire risk mitigation, the CPUC may not agree with SCE's position. Pursuant to the requirements of SB 901, a Commission on Catastrophic Wildfire Cost and Recovery was formed in January 2019 to examine, among other things, the socialization of catastrophic wildfire costs in an equitable manner. SB901 also provides an opportunity for utilities to securitize costs that are deemed just and reasonable by the CPUC for wildfires that occur after January 1, 2019 and, to the extent costs exceed the maximum amount the utility can pay without harming ratepayers or materially impacting the utility’s ability to provide adequate and safe services, for wildfires that occurred in 2017. Based on events and information available to date, SCE believes it is unlikely that it will seek to use this mechanism to securitize costs incurred in connection with the 2017/2018 Wildfire/Mudslide Events.

SCE continues to pursue legislative, regulatory and legal strategies to address the application of a strict liability standard to wildfire-related damages without the ability to recover resulting costs in electric rates. However, SCE cannot predict whether or when there will be a comprehensive solution mitigating the significant risk faced by California investor-owned utilities related to wildfires.

Permanent Retirement of San Onofre

The San Onofre OII proceeding regarding the steam generator replacement project at San Onofre and the related outages and subsequent shutdown of San Onofre was resolved in 2018 through the execution of a Revised San Onofre Settlement Agreement. On January 30, 2018, SCE, SDG&E, The Alliance for Nuclear Responsibility, The California Large Energy Consumers Association, California State University, Citizens Oversight dba Coalition to Decommission San Onofre, the Coalition of California Utility Employees, the Direct Access Customer Coalition, Ruth Henricks, ORA, TURN, and Women's Energy Matters (the "OII Parties") entered into a Revised San Onofre Settlement Agreement in the San Onofre OII proceeding (the "Revised San Onofre Settlement Agreement"). Under the Revised San Onofre Settlement Agreement, SCE and SDG&E (the "Utilities") will cease rate recovery of San Onofre costs as of the date their combined remaining San Onofre regulatory assets equal $775 million (the "Cessation Date"). The CPUC granted SCE's request to reduce the San Onofre regulatory asset by applying approximately $72 million of proceeds received from litigation with the U.S. Department of Energy (“DOE”) related to DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. As a result, the combined San Onofre regulatory asset balance for the Utilities reached $775 million on December 19, 2017 and SCE ceased recovery of San Onofre costs in rates beginning on December 20, 2017. SCE has refunded to customers approximately $155 million of San Onofre-related amounts recovered in rates on and after December 20, 2017. SCE will retain amounts collected under the Prior San Onofre Settlement Agreement before the Cessation Date. SCE will also retain $47 million of proceeds received in 2017 from arbitration with Mitsubishi Heavy Industries ("MHI") over MHI's delivery of faulty steam generators. In the Revised San Onofre Settlement Agreement, SCE retained the right to sell its stock of nuclear fuel and not share such proceeds with customers, as was provided in the Prior San Onofre Settlement Agreement. SCE intends to sell its nuclear fuel inventory as market conditions warrant. Sales of nuclear fuel may be significant.

The Revised San Onofre Settlement Agreement provides certain exclusions from the determination of SCE's ratemaking capital structure. Notwithstanding that SCE will no longer recover its San Onofre regulatory asset, the debt borrowed to finance the regulatory asset will continue to be excluded from SCE's ratemaking capital structure. Additionally, SCE may exclude the after-tax charge resulting from the implementation of the Revised San Onofre Settlement Agreement from its ratemaking capital structure. In connection with the Revised San Onofre Settlement Agreement, and in exchange for the release of certain San Onofre-related claims, the Utilities entered into an agreement ("Utility Shareholder Agreement") in which SCE agreed to pay SDG&E the amounts SDG&E would have received in rates under the Prior San Onofre Settlement Agreement but will not receive upon implementation of the Revised San Onofre Settlement Agreement. The following table summarizes the financial impact in 2017 of the Revised San Onofre Settlement Agreement and the Utility Shareholder Agreement:

(in millions)		
San Onofre base regulatory asset	$	696
DOE litigation regulatory liability		(72)
MHI Arbitration regulatory liability		(47)
GHG Reduction Program		(10)
Other		6
Present value of Utility Shareholder Agreement		143
Total pre-tax charge	$	716
Total after-tax charge	$	448

In July 2018, the CPUC approved all of the terms of the Revised San Onofre Settlement Agreement other than a provision under which SCE agreed to fund $10 million for a research, development and demonstration program intended to develop technologies and methodologies to reduce GHG emissions (the "Modification"). The Revised San Onofre Settlement Agreement with the Modification became effective on August 2, 2018, and SCE recorded a benefit related to the Modification during the third quarter of 2018.

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, operation and maintenance, monitoring and site closure. Unless there is a single 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.

At December 31, 2018, SCE's recorded estimated minimum liability to remediate its 21 identified material sites (sites with a liability balance as of December 31, 2018, in which the upper end of the range of the costs is at least $1 million) was $135 million, including $90 million related to San Onofre. In addition to these sites, SCE also has 15 immaterial sites with a liability balance at December 31, 2018 for which the total minimum recorded liability was $4 million. Of the $139 million total environmental remediation liability for SCE, $134 million has been recorded as a regulatory asset. SCE expects to recover $42 million through an incentive mechanism that allows SCE to recover 90% of its environmental remediation costs at certain sites (SCE may request to include additional sites) and $92 million through a mechanism that allows SCE to recover 100% of the costs incurred at certain sites 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.

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 the identified material sites and immaterial sites could exceed its recorded liability by up to $139 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.

SCE expects to clean up and mitigate its identified sites over a period of up to 30 years. Remediation costs for each of the next 5 years are expected to range from $6 million to $20 million. Costs incurred for years ended December 31, 2018, 2017 and 2016 were $8 million, $9 million and $4 million, respectively.

Based upon the CPUC's regulatory treatment of environmental remediation costs incurred at SCE, 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 estimates.

Nuclear Insurance

Federal law limits public offsite liability claims for bodily injury and property damage from a nuclear incident to the amount of available financial protection, which is currently approximately $14.1 billion for Palo Verde and $560 million for San Onofre. As of January 1, 2018, SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($450 million) through a Facility Form issued by American Nuclear Insurers ("ANI"). In the case of San Onofre, the balance is covered by a US Government indemnity. In the case of Palo Verde, 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, which is participating in the loss sharing program, results in claims and/or costs which exceed the primary insurance at that plant site, all participating nuclear reactor licensees could be required to contribute their share of the liability in the form of a deferred premium.

The ANI Facility Form coverage includes broad liability protection for bodily injury or offsite property damage caused by the nuclear energy hazard at San Onofre or Palo Verde, or while radioactive material is in transit to or from San Onofre or Palo Verde. The Facility Form, however, includes several exclusions. First, it excludes onsite property damage to the nuclear facility itself and onsite cleanup costs, but as discussed below SCE maintains separate Nuclear Electric Insurance Limited ("NEIL") property damage coverage for such events. Second, tort claims of onsite workers are excluded, but SCE also maintains an ANI Master Worker Form policy that provides coverage for non-licensee workers. This program provides a shared industry aggregate limit of $450 million. Industry losses covered by this program could reduce limits available to SCE. Third, offsite environmental costs arising out of government orders or directives, including those issued under the Comprehensive Environmental Response, Compensation and Liability Act, also known as CERCLA, are excluded, with minor exceptions from clearly identifiable accidents.

SCE withdrew from participation in the secondary insurance pool for San Onofre for offsite liability insurance effective January 5,

2018. Based on its ownership interests in Palo Verde, SCE could be required to pay a maximum of approximately $65 million per nuclear incident for future incidents. However, it would have to pay no more than approximately $9.7 million per future incident in any one year. SCE could be required to pay a maximum of approximately $255 million per nuclear incident and a maximum of $38 million per year per incident for liabilities arising from events prior to January 5, 2018, although SCE is not aware of any such events. 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.

SCE is a member of NEIL, a mutual insurance company owned by entities with nuclear facilities. NEIL provides insurance for nuclear property damage, including damages caused by acts of terrorism up to specified limits, and for accidental outages for active facilities. The amount of nuclear property damage insurance purchased for San Onofre and Palo Verde exceeds the minimum federal requirement of $50 million and $1.06 billion, respectively. These policies include coverage for decontamination liability. Additional outage insurance covers part of replacement power expenses during an accident-related nuclear unit outage. The accidental outage insurance at San Onofre has been canceled as a result of the permanent retirement, but that insurance continues to be in effect at Palo Verde.

If NEIL 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 $52 million per year. Insurance premiums are charged to operating expense.

Spent Nuclear Fuel

Under federal law, the 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 has not met its contractual obligation to accept spent nuclear fuel. 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 their current license period.

In June 2010, the United States Court of Federal Claims issued a decision granting SCE and the San Onofre co-owners damages of approximately $142 million (SCE share $112 million) to recover costs incurred through December 31, 2005 for the DOE's failure to meet its obligation to begin accepting spent nuclear fuel from San Onofre. SCE received payment from the federal government in the amount of the damage award. In April 2016, SCE, as operating agent, settled a lawsuit on behalf of the San Onofre owners against the DOE for $162 million (SCE share $124 million, which included reimbursement for approximately $2 million in legal and other costs), to compensate for damages caused by the DOE's failure to meet its obligation to begin accepting spent nuclear fuel for the period from January 1, 2006 to December 31, 2013. In August 2018, the CPUC approved SCE's proposal to return the SCE share of the award to customers based on the amount that customers actually contributed for fuel storage costs, resulting in approximately $105.6 million of the SCE share being returned to customers and the remaining $16.6 million being returned to shareholders. Of the $105.6 million, $71.6 million was applied against the remaining San Onofre Regulatory Asset in accordance with the Revised San Onofre Settlement Agreement.

The April 2016 settlement also provided for a claim submission/audit process for expenses incurred from 2014 – 2016, where SCE may submit a claim for damages caused by the DOE failure to accept spent nuclear fuel each year, followed by a government audit and payment of the claim. This process made additional legal action to recover damages incurred in 2014 – 2016 unnecessary. The first such claim covering damages for 2014 – 2015 was filed on September 30, 2016 for approximately $56 million. In February 2017, the DOE reviewed the 2014 – 2015 claim submission and reduced the original request to approximately $43 million (SCE share was approximately $34 million). SCE accepted the DOE's determination, and the government paid the 2014 – 2015 claim under the terms of the settlement. In October 2017, SCE filed a claim covering damages for 2016 for approximately $58 million. In May 2018, the DOE approved reimbursement of approximately $45 million (SCE share was approximately $35 million) of SCE's 2016 damages, disallowing recovery of approximately $13 million. SCE accepted the DOE's determination, and the government paid the 2016 claim under the terms of the settlement. The damages awards are subject to CPUC review as to how the amounts will be refunded among customers, shareholders, or to offset other costs.

ITEM 3.

N/A

ITEM 4.

These accounts are used where applicable. The balance for unamortized loss on reacquired debt (account number 189.XXX) at December 31, 2018 was approximately $153 million. There was no unamortized gain (account number 257.XXX) recorded at December 31, 2018.

ITEM 5.

CPUC holding company rules require that SCE's dividend policy be established by SCE's Board of Directors on the same basis as if SCE were a stand-alone utility company, and that the capital requirements of SCE, as deemed to be necessary to meet SCE's electricity service obligations, shall receive first priority from the Boards of Directors of both Edison International and SCE. In addition, the CPUC regulates SCE's capital structure which limits the dividends it may pay to its shareholders. Under SCE's interpretation of CPUC regulations, the common equity component of SCE's capital structure must remain at or above 48% on a weighted average basis over the 37-month period that SCE's capital structure is in effect for ratemaking purposes. As allowed under the Revised San Onofre Settlement Agreement, which was approved by the CPUC in July 2018, SCE has excluded a $448 million after-tax charge resulting from the implementation of the Revised San Onofre Settlement Agreement from its ratemaking capital. At December 31, 2018, SCE's 37-month average common equity component of total capitalization was 49.7% and the maximum additional dividend that SCE could pay to Edison International under this limitation after paying preferred and preference shareholders was $459 million, resulting in a restriction on net assets of approximately $13.3 billion.

Under SCE's interpretation of the CPUC's capital structure decisions, SCE is required to file an application for a waiver of the 48% equity ratio condition discussed above if an adverse financial event reduces its spot equity ratio below 47%. On February 28, 2019, SCE submitted an application to the CPUC for waiver of compliance with this equity ratio requirement, describing that while the charge accrued in connection with the 2017/2018 Wildfire/Mudslide Events caused its equity ratio to fall below 47% on a spot basis as of December 31, 2018, SCE remains in compliance with the 48% equity ratio over the applicable 37-month average basis. In its application, SCE is seeking a limited waiver to exclude wildfire-related charges and wildfire-related debt issuances from its equity ratio calculations until a determination regarding cost recovery is made. Under the CPUC's rules, SCE will not be deemed to be in violation of the equity ratio requirement, and therefore may continue to issue debt and dividends, while the waiver application is pending resolution. For further information, see Item 2 above.

As a California corporation, SCE's ability to pay dividends is also governed by its obligations under the California General Corporation Law. California law requires that for a dividend to be declared: (a) retained earnings must equal or exceed the proposed dividend, or (b) immediately after the dividend is made, the value of the corporation's assets must exceed the value of its liabilities plus amounts required to be paid in order to liquidate stock senior to the shares receiving the dividend.
Additionally, a California corporation may not declare a dividend if it is, or as a result of the dividend, would be, likely to be unable to meet its liabilities as they mature. Prior to declaring dividends, SCE's Board of Directors evaluates available information, including when applicable, information pertaining to the 2017/2018 Wildfire/Mudslide Events, to ensure that the California law requirements for the declarations are met. On February 28, 2019, SCE declared a dividend to Edison International of $200 million.

ITEM 6.

See responses to Items 1 and 2 above.

ITEM 7.

See responses to Items 1 and 2 above.

ITEM 8.

See responses to Items 1 and 2 above.

ITEM 9.

See responses to Items 1 and 2 above.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	923,644			(21,370,551)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(918,039)			3,429,727
3	Preceding Quarter/Year to Date Changes in Fair Value	1,047,909			(1,834,333)
4	Total (lines 2 and 3)	129,870			1,595,394
5	Balance of Account 219 at End of Preceding Quarter/Year	1,053,514			(19,775,157)
6	Balance of Account 219 at Beginning of Current Year	1,053,514			(19,775,157)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(4,600,552)			4,111,456
8	Current Quarter/Year to Date Changes in Fair Value	3,547,038			(6,910,493)
9	Total (lines 7 and 8)	(1,053,514)			(2,799,037)
10	Balance of Account 219 at End of Current Quarter/Year				(22,574,194)

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			(20,446,907)	[redacted]	[redacted]
2			2,511,688	[redacted]	[redacted]
3			(786,424)	[redacted]	[redacted]
4			1,725,264	1,136,096,464	1,137,821,728
5			(18,721,643)	[redacted]	[redacted]
6			(18,721,643)	[redacted]	[redacted]
7			(489,096)	[redacted]	[redacted]
8			(3,363,455)	[redacted]	[redacted]
9			(3,852,551)	(189,375,585)	(193,228,136)
10			(22,574,194)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	44,379,224,913	44,334,189,662
4	Property Under Capital Leases	46,441,102	46,441,102
5	Plant Purchased or Sold		
6	Completed Construction not Classified	3,871,681,419	3,871,681,419
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	48,297,347,434	48,252,312,183
9	Leased to Others		
10	Held for Future Use	30,786,587	30,786,587
11	Construction Work in Progress	3,882,962,828	3,879,243,378
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	52,211,096,849	52,162,342,148
14	Accum Prov for Depr, Amort, & Depl	13,841,299,847	13,816,271,048
15	Net Utility Plant (13 less 14)	38,369,797,002	38,346,071,100
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	13,289,891,596	13,264,862,797
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	551,408,251	551,408,251
22	Total In Service (18 thru 21)	13,841,299,847	13,816,271,048
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)	13,841,299,847	13,816,271,048

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

Gas (d)	Other (Specify) WATER (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
6,330,758	37,703,992			1,000,501	3
					4
					5
					6
					7
6,330,758	37,703,992			1,000,501	8
					9
					10
13,686	2,890,935			814,829	11
					12
6,344,444	40,594,927			1,815,330	13
1,941,583	22,502,068			585,148	14
4,402,861	18,092,859			1,230,182	15
					16
					17
1,941,583	22,502,068			585,148	18
					19
					20
					21
1,941,583	22,502,068			585,148	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,941,583	22,502,068			585,148	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials	56,310,370	39,902,411
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	56,310,370	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)	173,835,318	35,292,470
10	SUBTOTAL (Total 8 & 9)	173,835,318	
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)	103,525,880	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	126,619,808	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
	35,292,470	60,920,311	3
			4
			5
		60,920,311	6
			7
			8
	38,075,588	171,052,200	9
		171,052,200	10
			11
			12
-35,789,156	38,075,588	101,239,448	13
		130,733,063	14
			15
			16
			17
			18
			19
			20
			21
			22

Schedule Page: 202 Line No.: 3 Column: e
Transfer of costs from fuel in process to fuel in the reactor (Account 120.1 - $35,292,470)

Schedule Page: 202 Line No.: 9 Column: e
Retired fully amortized batch. (Account 120.3 and Account 120.5 - $38,075,588)

Schedule Page: 202 Line No.: 13 Column: e
Retired fully amortized batch. (Account 120.3 and Account 120.5 - $38,075,588)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	2,948,240	
3	(302) Franchises and Consents	132,598,210	23,833,916
4	(303) Miscellaneous Intangible Plant	1,189,323,866	158,505,113
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	1,324,870,316	182,339,029
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	256,543	
9	(311) Structures and Improvements	722,796	
10	(312) Boiler Plant Equipment	1,059,643	
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment	431,142	
15	(317) Asset Retirement Costs for Steam Production		
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	2,470,124	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	2,374,247	621,064
19	(321) Structures and Improvements	609,413,089	30,058,303
20	(322) Reactor Plant Equipment	739,331,504	2,687,671
21	(323) Turbogenerator Units	277,802,667	-1,396,855
22	(324) Accessory Electric Equipment	209,587,819	-15,810,933
23	(325) Misc. Power Plant Equipment	124,457,220	10,710,561
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	1,962,966,546	26,869,811
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	4,977,461	
28	(331) Structures and Improvements	225,821,731	2,621,715
29	(332) Reservoirs, Dams, and Waterways	562,573,681	34,698,825
30	(333) Water Wheels, Turbines, and Generators	184,379,149	11,824,956
31	(334) Accessory Electric Equipment	218,120,356	747,399
32	(335) Misc. Power PLant Equipment	12,359,923	801,441
33	(336) Roads, Railroads, and Bridges	19,286,163	1,299,332
34	(337) Asset Retirement Costs for Hydraulic Production	7,353,305	-1,701,994
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	1,234,871,769	50,291,674
36	D. Other Production Plant		
37	(340) Land and Land Rights	3,745,317	
38	(341) Structures and Improvements	96,873,380	13,191,421
39	(342) Fuel Holders, Products, and Accessories	16,530,532	6,940
40	(343) Prime Movers	1,192,732,852	17,973,011
41	(344) Generators	125,498,405	2,301,043
42	(345) Accessory Electric Equipment	189,005,184	15,275,626
43	(346) Misc. Power Plant Equipment	115,267,949	354,363
44	(347) Asset Retirement Costs for Other Production	36,901,422	-8,472,602
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,776,555,041	40,629,802
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,976,863,480	117,791,287

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	343,195,020	106,582
49	(352) Structures and Improvements	879,621,910	98,635,647
50	(353) Station Equipment	5,902,949,228	231,983,082
51	(354) Towers and Fixtures	2,343,145,352	12,745,972
52	(355) Poles and Fixtures	1,292,702,467	227,282,481
53	(356) Overhead Conductors and Devices	1,524,531,167	133,327,661
54	(357) Underground Conduit	256,348,021	15,139,018
55	(358) Underground Conductors and Devices	376,710,004	24,362,569
56	(359) Roads and Trails	193,773,411	1,723,647
57	(359.1) Asset Retirement Costs for Transmission Plant	14,487,081	-7,819,273
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	13,127,463,661	737,487,386
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	125,242,449	797,225
61	(361) Structures and Improvements	644,469,720	57,976,194
62	(362) Station Equipment	2,539,477,720	222,893,101
63	(363) Storage Battery Equipment		663
64	(364) Poles, Towers, and Fixtures	2,971,657,095	213,371,833
65	(365) Overhead Conductors and Devices	1,673,858,965	200,703,091
66	(366) Underground Conduit	2,162,291,863	240,670,919
67	(367) Underground Conductors and Devices	6,286,753,800	248,946,076
68	(368) Line Transformers	3,907,145,297	398,895,177
69	(369) Services	1,406,863,413	89,636,458
70	(370) Meters	1,002,354,513	12,358,842
71	(371) Installations on Customer Premises		12,372,731
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	904,155,468	44,824,314
74	(374) Asset Retirement Costs for Distribution Plant	8,491,620	-1,176,530
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	23,632,761,923	1,742,270,094
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	32,024,726	2,934
87	(390) Structures and Improvements	1,059,661,781	46,300,951
88	(391) Office Furniture and Equipment	744,007,686	111,302,925
89	(392) Transportation Equipment	15,403,794	7,717,401
90	(393) Stores Equipment	11,578,909	181,133
91	(394) Tools, Shop and Garage Equipment	97,052,927	7,100,941
92	(395) Laboratory Equipment	114,276,292	7,285,539
93	(396) Power Operated Equipment	816,474	40,473
94	(397) Communication Equipment	978,034,932	82,967,183
95	(398) Miscellaneous Equipment	41,663,510	3,942,394
96	SUBTOTAL (Enter Total of lines 86 thru 95)	3,094,521,031	266,841,874
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	7,641,303	921,412
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	3,102,162,334	267,763,286
100	TOTAL (Accounts 101 and 106)	46,164,121,714	3,047,651,082
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)	46,164,121,714	3,047,651,082

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			2,948,240		2
			156,432,126		3
295,664,092		198,565	1,052,363,452		4
295,664,092		198,565	1,211,743,818		5
					6
					7
715			255,828		8
722,796					9
1,059,643					10
					11
					12
					13
431,142					14
					15
2,214,296			255,828		16
					17
			2,995,311		18
786,113		2,113	638,687,392		19
8,369			742,010,806		20
204,331			276,201,481		21
7,335			193,769,551		22
729,235			134,438,546		23
					24
1,735,383		2,113	1,988,103,087		25
					26
			4,977,461		27
420,993			228,022,453		28
25,866			597,246,640		29
27,933			196,176,172		30
298,419			218,569,336		31
			13,161,364		32
			20,585,495		33
			5,651,311		34
773,211			1,284,390,232		35
					36
			3,745,317		37
23,274			110,041,527		38
			16,537,472		39
1,242,720			1,209,463,143		40
242,969			127,556,479		41
324,435		3,904,907	207,861,282		42
			115,622,312		43
			28,428,820		44
1,833,398		3,904,907	1,819,256,352		45
6,556,288		3,907,020	5,092,005,499		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
65,390		-6,117	343,230,095		48
3,818,819		9,312,335	983,751,073		49
65,664,113		2,868,970	6,072,137,167		50
112,323			2,355,779,001		51
18,470,938		-1,318,129	1,500,195,881		52
4,593,851		-171,546	1,653,093,431		53
			271,487,039		54
1,719,929		-13,099	399,339,545		55
			195,497,058		56
			6,667,808		57
94,445,363		10,672,414	13,781,178,098		58
					59
11,477			126,028,197		60
5,853,017		-90,635	696,502,262		61
34,277,690		-273,729	2,727,819,402		62
		-663			63
38,649,419		1,317,820	3,147,697,329		64
31,883,817		178,085	1,842,856,324		65
12,229,690		-62,478	2,390,670,614		66
48,305,966			6,487,393,910		67
86,791,325		13,099	4,219,262,248		68
2,149,448			1,494,350,423		69
3,462,293			1,011,251,062		70
			12,372,731		71
					72
86,868,204			862,111,578		73
			7,315,090		74
350,482,346		1,081,499	25,025,631,170		75
					76
					77
					78
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					81
					82
					83
					84
					85
		-2,113	32,025,547		86
17,862,017		-8,256,581	1,079,844,134		87
78,188,915		-3,740,852	773,380,844		88
6,127,848			16,993,347		89
902,077			10,857,965		90
5,861,677			98,292,191		91
3,036,430		663	118,526,064		92
			856,947		93
150,581,050		38,174	910,459,239		94
92,401			45,513,503		95
262,652,415		-11,960,709	3,086,749,781		96
					97
			8,562,715		98
262,652,415		-11,960,709	3,095,312,496		99
1,009,800,504		3,898,789	48,205,871,081		100
					101
					102
					103
1,009,800,504		3,898,789	48,205,871,081		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1	NONE.				
2					
3					
4					
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6					
7					
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45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	350 - Land and Land Rights:			
3				
4				
5	Under $250,000			
6				
7				
8	360 - Land and Land Rights:			
9				
10				
11	Under $250,000			
12				
13				
14				
15	350 - Land and Land Rights:			
16				
17				
18	Over $250,000 (1)	2011		15,781,292
19	Over $250,000 (2)	2018		15,005,295
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
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43				
44				
45				
46				
47	Total			30,786,587

Schedule Page: 214 Line No.: 18 Column: c

Pending CPUC Decision

Schedule Page: 214 Line No.: 19 Column: c

Pending CPUC Decision

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	WORK ORDERS OVER $1,000,000	
2	FIP-Mesa Substation: Build new Mesa	200,974,336
3	FIP-WOD 220 kV Trans Line Installat	145,532,247
4	CSRP - Back Office	68,341,542
5	FIP-West of Devers Upgrade Project:	65,534,809
6	SYLMAR/LADWP - AC/DC Filter Replace	48,788,132
7	8191-5001--Falcon Ridge: Licensing	46,881,213
8	Chino: equip 1A pos with CBs	44,265,636
9	GM - Cybersecurity - Master	42,761,169
10	La Fresa Sub (Phase 2): Install ne	42,216,633
11	CSRP - Foundational	39,012,319
12	8065-5001--Alberhill: Licensing Pha	37,920,260
13	Phase 1: Chino Sub: Install 40 new	35,761,501
14	Grid Data Center Program	35,031,503
15	Devers Red Bluff No.1 TLRR 99 Disc	33,294,364
16	CSRP - Front Office	27,751,589
17	VA-4950-0353--IVYGLEN: BRING IN SEC	25,587,935
18	SD-cGIS Improvements - Capital	25,425,814
19	Ridgecrest SC - Facility Upgrade -	25,209,538
20	GM - Long-Term Plan Tool - Master	24,744,861
21	Magunden-Vestal No.2 220kV-TLRR	24,229,391
22	Sylmar Submarine Electrode Replacem	23,349,469
23	GM - Grid & DER Mgmt - Master	21,301,027
24	GM - Field Area Network (FAN)	20,378,465
25	VA-4950-0435--ET-SE-SANJACIN* VALLE	19,982,036
26	DH J.Shumaker/C.Hotta R/R 9 TRANS	19,308,576
27	EMS Refresh	17,950,147
28	MESA 500KV SUB UG MESANARROW PIN 7	17,913,993
29	Serrano Substation:	17,576,009
30	CFF~Natural Sub: Phase 2- Construct	17,031,260
31	VA-CONSTRUCT APPROXIMATELY 12.5MILE	16,195,404
32	FIP-Lugo Sub: Upgrade Terminal Equi	15,592,709
33	Highgrove rebuild swtrack Add MEER(	14,706,909
34	Magunden-Vestal No.1 220kV-TLRR	14,489,473
35	MESA 500KV SUB UG MESANEWMARKPIN 7	14,417,277
36	PSC CRAS RGOOSE Core System	14,325,678
37	SC CM STORM: THOMAS FIRE 12/5/2017	14,112,493
38	8116-5001--Circle City (formerly Ho	14,072,838
39	SD-Energy Trading System Refresh-Ca	13,842,761
40	Walnut: Equip banks w/ circuit brea	13,813,246
41	GO1 Workplace Upgrade - CAP	13,688,043
42	RI-FALCON RIDGE 66/12 PIN 5397	13,626,395
43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	C&C Visibility Expansion phase 2	12,969,803
2	WOD UPGRADE RELOCATE PIN 642004	12,226,633
3	Carbgn-Hanjn-Lng Bch 66kV:Rplc twrs	12,122,987
4	Mira Loma Rpl #1AA Bank 500/220kV	11,985,646
5	Johanna-Instll new 220/66 bank addi	11,806,772
6	FIP-Inst Eldo-Lug-Mhve Series Caps	11,312,212
7	FIP-Eldorado Sub: Upgrade Terminal	11,108,372
8	FIP-Mid-Line Cap:Inst cap on Eldor	10,732,858
9	GM - Grid Analytics App - Master	10,724,632
10	Safari Sub: Install 2 28MVA 33/12 L	10,688,883
11	2017 C&C Perimeter - PAN	10,358,588
12	Lugo - Replace No. 2AA Bank 500/220	10,233,407
13	FIP-Mohave Sub:Install CBs, Disc.&s	10,089,322
14	I:Lugo: Inst 500kV double breakers	9,975,060
15	DEFERRED MPR - Replace HB Valve	9,700,021
16	Springville Sub: Redesign high side	9,669,413
17	Colton: Install SA2.	9,109,272
18	Integration Capacity Analysis (ICA)	9,077,775
19	CRAS RGOOSE Conversion and Test Env	9,042,703
20	GM - Grid Connectivity Model - Mast	8,887,775
21	SD-Skype Voice- Enterprise Deployme	8,835,540
22	Windows 10 Upgrade Project	8,615,912
23	C&C Data loss prevention(DLP)enhanc	8,489,333
24	EldoradoMohave500kV:Install 3 struc	8,290,135
25	4570-8206--ET-01738*DEVERS-CARODEAN	8,032,700
26	CO Nava: Westeryly u.g. work order.	7,776,907
27	BC4 - Relicensing	7,769,815
28	Royal:Upgrade 66kV relays & equipme	7,724,601
29	CRRdBlf#1: TLRR Remediate Discrepan	7,720,128
30	MPO: Falcon Ridge, Rancho Cucamonga	7,689,529
31	Bailey-Pastoria 220kV-TLRR	7,480,941
32	SD-Digital Managed Services -Mig Se	7,413,781
33	EMT betterment order	7,324,124
34	BISHOP SC - Facility Upgrade- CAP	7,114,530
35	SD-WM Portfolio Mgmt- P6 Integratio	7,101,240
36	MPPH-Replace #1 and 2 Transformer B	7,057,090
37	DSP DSPDSP	6,978,903
38	U_Midway - Delano FO Cable(07074)_R	6,953,350
39	2016 C&C Interior Defense TTNM	6,922,291
40	36 Antelope Valley ESIP on Pronghor	6,906,828
41	GO1 - Electrical Upgrades 2015-2019	6,894,825
42	Leatherneck Sub: Licensing Phase -	6,549,495
43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	1867-9999-PV PREPAID RECORDED CAPIT	6,502,225
2	DERMS - BackOffice Hardware	6,490,187
3	Santa Ana on the Titanium 12kV line	6,487,870
4	ACQ: West of Devers (WOD)_FERC	6,354,081
5	46 RULE 20A - UG INSTALL RULE 20A -	6,270,011
6	Lee Vining Sub: Rebuild Substation	6,226,289
7	GM - Gen Intercon App - Master	6,147,661
8	TLRR PRI A-2 4702585 (1660)	5,949,102
9	FIP-Relocation of the Laguna Bell-R	5,925,776
10	Blythe Service Center Upgrade-CAP	5,910,862
11	2017 C&C Perimeter - CSC	5,857,987
12	CFF~Carodean Sub: Modify 115kV Swit	5,732,944
13	5026-8202--EL SEGUNDO: CONNECT UNIT	5,723,767
14	Visalia Substation: Rebuild 12 kV s	5,717,049
15	Mesa: MWD 50% MWD Water Line Reloca	5,707,100
16	CS Re-platform Planning IOC	5,671,161
17	2016 Log Archive Upgrade and Expans	5,647,707
18	PREVENTIVE MAINT (ELECTIVE OPTION)	5,563,894
19	Colton Sub: Replace (12) 12kV CBs	5,509,846
20	SD-ISP Upgrade	5,434,449
21	IOC Visibility Expansion - C&C	5,410,852
22	Mira Loma Sub: Install On-Line DGA	5,371,094
23	PV2ER-Polar Crane U2	5,330,287
24	Camp Edison-Admn/Whse Remod-CAP	5,257,958
25	FIP-I: Calcite:new 220kV Interconne	5,220,452
26	Eldorado-Lugo: CA-Install OPGW	5,162,959
27	DH L.Harvey/C.Hotta CAP ONRAMP CABL	5,144,686
28	Goshen-Install (2) 66/12 Banks	4,999,665
29	Network Management System (NMS) Upg	4,979,404
30	FIP-San Bernardino Sub:Install 220k	4,813,924
31	5054-5093--VINCENT: INSTALL ONLINE	4,809,571
32	EldradoMoenkopi500kV:Replace 1 stru	4,694,145
33	Serrano:Rplace 1AA/2AA Spare Transf	4,669,340
34	Chino Sub: Ph2 Add 4th 280 MVA xfrm	4,662,981
35	SD - AUD Refresh	4,643,060
36	Vincent Sub:PHY-Physical Security P	4,634,437
37	CFF~Recovery Substation:	4,623,489
38	CS Re-platform Planning ADC HW	4,612,625
39	Deferred -HL-Dam 1&2 Replace Contro	4,594,976
40	Ivyglen Sub: Preliminary engineeri	4,591,726
41	5026-5015 EL SEGUNDO: ENGINEERING,	4,572,943
42	Rector Substation - Replace the 220	4,554,759
43	TOTAL	3,879,243,378

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	SD-TSFT Replacement-Test Smart Form	4,436,947
2	CS-Lugo Sub-CIP 014 Program	4,428,444
3	88 2018 LS-1 LED CONVERSION PROJECT	4,378,625
4	BROADWSA - Grid Data Center - IOC	4,351,872
5	2016-2018 Seismic Assessmnt Prog -	4,312,159
6	Midway:Replc protection on series c	4,245,056
7	2017 Visibility - Perimeter	4,225,394
8	DsrtStrWhrlwnd220kV GenTie Install	4,209,715
9	5067-5033--DEVERS: INSTALL ONLINE D	4,156,818
10	WADHWASM-14I-NewCommRoom-Lighthipe	4,071,993
11	U_Carpinteria-Ventura FO Cable 0614	4,051,598
12	KAW-Kaweah Relicensing (FERC #298)	4,023,727
13	Grid Analytics Application (GAA) -	4,008,239
14	CS-Foothill SC-New Security Compone	3,962,748
15	C&C Interior Protection - FRSCT Pha	3,950,475
16	GM - Common Substation Platform (CS	3,948,115
17	Knowledge Base AI Platform-Infosys	3,857,490
18	CS-Pardee Sub-CIP 014 Program	3,857,038
19	AFUDC for CPUC Portion of 900959223	3,834,546
20	CS-Mira Loma Sub-CIP 014 Program	3,823,664
21	Sawetelle: Replace (2) 66/16kV XFMR	3,820,848
22	PREVENTIVE MAINT (ELECTIVE OPTION)	3,808,316
23	TRTP 1: FIP Antelope-Pardee 500kV:	3,805,950
24	GM - Data Integration - Master	3,783,983
25	SD-Energy Market Systems Refresh-Ca	3,724,054
26	Atwood: Replace existing SAS with S	3,723,549
27	Colton Substation: Replace No. 1 an	3,717,997
28	SBCRP SEGMENT 1<(>&<)>2 INSTALL OPG	3,693,818
29	Devers: Install necessary phasor me	3,688,318
30	ACQ: West of Devers (WOD)_CPUC	3,683,723
31	PVCER - Main Generator Stator Rewin	3,676,639
32	Laguna Bell: Replace (18) LBFB Rela	3,670,403
33	RI Mira Loma Substation-New Control	3,649,815
34	2015 C&C Interior Protection - Cyln	3,605,609
35	SD-HR Onboarding BPM (Pega)	3,603,227
36	Pebbly Beach Sub: Rebuild switchgea	3,601,342
37	DSP DSP4KV CUT OVER ENGINEER:	3,549,263
38	C&C Cloud Visibility	3,538,678
39	FIP-Lugo-Mohave T/L(CA): Instal OPG	3,458,579
40	RULE 20A - UG INSTALL	3,448,923
41	SD-OMS V6 Refresh-Custom Enhance Ma	3,383,141
42	8564-5001--Presidential Sub: Licens	3,359,296
43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	La Fresa:Replace No. 3A Bank 220/66	3,306,297
2	CFF~5057-5001--Wildlife: Engineer,	3,300,696
3	DERMS - Energy Storage Software	3,294,158
4	CFF~Process 66/12kV Substation: Ins	3,260,778
5	SD-(DES) Release 9-MyAcct/Billing &	3,259,574
6	SC CM STORM: WOOLSEY FIRE 11/8/2018	3,241,665
7	CFF DH~ J.Hunter~ CFF~Nietos Sub: R	3,215,932
8	Laguna Bell Sub: Replace No. 1A Ban	3,197,660
9	DSP DSPPIF-430003 NEW DSP CIRCUIT C	3,185,735
10	RULE 20A - UG INSTALL	3,158,327
11	GO Seismic Upgrades (CLIENT FUNDED)	3,148,937
12	FIP-Devers Sub: Install 220 kV CBs	3,141,351
13	Barre: Replace (40) existing 66 kV	3,131,230
14	DSP DSP4KV CUT OVER ENGINEER:	3,053,749
15	La Mirada: Replace existing SAS w S	3,044,422
16	Mohave Sub: Install CBs 732 & 832	3,029,134
17	Washington:Replace existing SAS w/	3,019,162
18	BAKKERJA-14I-MesaLoopIn-MesaSubstat	3,002,721
19	Chatham-Rebuild 12kV Switchrack	3,002,711
20	SP T&D Asmt Trans Corridor Geotechn	2,980,305
21	Sullivan Sub:Add Xfmr Bank & Cap,re	2,967,420
22	U_Banducci-Monolith No1 (07042)_RLR	2,962,227
23	Santa Clara: Install necessary phas	2,913,009
24	Chatsworth: Replace No. 1 Bank 66/1	2,908,902
25	2014 C&C - SW - Perimeter - DNS	2,898,097
26	GO1- R/R Office/Conf Rm Glass Parti	2,894,514
27	2018 Vulnerability Management	2,875,473
28	SD-WM Portfolio Management - PPM Ph	2,864,185
29	Kernville SC - Facility Upgrade - C	2,828,134
30	Laguna Bell: Replace 14 existing 66	2,825,484
31	2018 Perimeter C&C IP MTD Platform	2,823,738
32	44 CITY OF TORRANCE 2018 LS-1 LED C	2,793,021
33	Supplier Portal Decommissioning- Ca	2,704,838
34	SD-DMS - API Services- WkS2	2,686,985
35	FIP-Vista Sub: Install 220 kV DSs	2,676,093
36	Colorado River Sub: CRAS Project Ph	2,638,340
37	DSP DSP748011 LAMBDA 12KV % TELEGRA	2,633,075
38	IR Automation Phase II	2,631,632
39	5080-5046--SERRANO: INSTALL ONLINE	2,631,598
40	PLANT BETTERMENT/UPGRADING DISTRIBU	2,618,344
41	C&C Threat Management Console	2,612,259
42	RELOCATE FACILITIES	2,609,252
43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	CFF~Carnival Sub: Install new 66kV	2,589,230
2	CS - Antelope Service Center Upgrad	2,567,163
3	Alder: Extend 66kV switcrck & equip	2,520,516
4	2018 Interior - RF Phase II	2,519,270
5	GM - Grid Connectivity Model - IT	2,512,974
6	CFF~Whirlwind(POS): Equip 220kV pos	2,511,900
7	VESTAL-COLUMBINE-DELANO-EARLIMART 6	2,509,060
8	BSH - Lundy Reline Return Ditch	2,490,390
9	PIN 4518 SBCRP STAGING YARDS	2,480,915
10	CCS Phase 3- Rel 2 CRAS Integration	2,474,410
11	FIP-LagunaBell-RioHondo: Install 1	2,473,076
12	Tapia:Rebld66kVGIS+16kV swrk;replc	2,466,329
13	Red Bluff Substation:	2,447,342
14	Johanna:Install double breakers on	2,446,684
15	CFF~ColRvr(NU): 220kV Line/Bank Pos	2,434,966
16	RE VESTAL-MARIPOSA 66KV RECONDUCTOR	2,424,975
17	Redlands SC - Facility Upgrade- CAP	2,415,766
18	CAP ON RAMP RELOCATON EXISTING	2,406,091
19	46-LONG BEACH FAO LED REPLACEMENT P	2,389,344
20	Citrus: Replace existing SAS with S	2,358,272
21	DSP DSPSTIRRUP SUB IR-BRIDLE 4KV CU	2,354,864
22	51 VISALIA LS-1 LED PROJECT 2-2018	2,353,293
23	Fernwood Sub: SAS to SA3 Conversion	2,346,580
24	Poplar Sub: Rpl No1 Bank	2,340,649
25	PREVENTIVE MAINT (ELECTIVE OPTION)	2,335,175
26	PREVENTIVE MAINT (ELECTIVE OPTION)	2,314,042
27	Valley Sub: Equip a new 115 kV posi	2,306,395
28	PLANT BETTERMENT/UPGRADING DISTRIBU	2,301,920
29	U_MOORPARK-PARDEE FW REFRESH	2,300,954
30	SA-48-ACCESSROAD CH CAMP PENDELTON,	2,282,127
31	Database Upgrade Assessment	2,279,033
32	Moorpark-Seismic- Recond,replce bus	2,262,486
33	FIP-Mesa-Vincent1: Install 2 strcts	2,254,899
34	MOBILE HOME PARK CONVERSION MOBILE	2,251,221
35	Clarifiers Life Extension T2	2,248,971
36	FIP-Mesa-Redondo 220kV: Install 4 s	2,242,599
37	PV3PM - SP-666 Repl SP Filtration S	2,231,978
38	Walnut/CFF Install two new CBs, one	2,224,731
39	CFF~Eldorado: Install (2) 220kV CBs	2,205,593
40	Crater: LCB rlys, hi-spd rlys, MEER	2,189,732
41	Big Creek 1-Rctr TLRR Remediation S	2,165,282
42	Lugo-Mira Loma No.3 500kV Ph2-TLRR	2,161,789
43	TOTAL	3,879,243,378

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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	FIP-Laguna Bell Sub:Replace (4) 230	2,160,098
2	DSP	2,151,056
3	Rosamond Substation:	2,132,025
4	Control-Silver Peak-Zack Segment TL	2,123,148
5	SD-Gen Automation Standardization -	2,120,386
6	Mira Loma-Serrano 1 500kV-MetroEast	2,091,978
7	5061-5098--LUGO: INSTALL ONLINE DIS	2,086,391
8	2016 Data Loss Prevention Enh - Dat	2,086,199
9	Laguna Bell Sub: Replace (19) 66kV	2,084,916
10	Lark Ellen: Replace existing SAS w	2,083,499
11	SD- IGAM-Identity Gov Access Mgmt-S	2,082,623
12	51 CLAIM PIER FIRE REPLACE DAMAGED	2,076,560
13	CS Re-Platform Captial	2,076,433
14	Maxwell 115/12 (D) - Replace (2) 11	2,072,039
15	8012-5025--MIRAGE: INSTALL ONLINE D	2,067,125
16	DH LA CIENEGA-BVRLY-CULVER RECABLE	2,062,212
17	IGAM - Service Establishment - Labo	2,044,640
18	Kramer(IF):Int.FacilitiesforWaterVa	2,043,995
19	ACQ: Santa Barbara Reliability_MPO	2,016,839
20	CFF~Webmet: Construct new 66/12 kV	2,016,624
21	Skylark-Upgrade Security Fence and	1,982,394
22	PV1PM - Rad Monitoring System Monit	1,967,592
23	PLANT BETTERMENT OUTSOURCE 555 8/3/	1,966,236
24	EPCR - Implementation Optimization	1,953,359
25	Devers-Seismic-Recn,replc cb,instl	1,949,602
26	CS-Irvine Operations Center-CIP 014	1,937,642
27	LINE EXTENSION LINE EXTENSION	1,901,365
28	Beverly Sub: Inst Stdrd Facility eq	1,898,822
29	MPR-Shakeflat Creek Crossing Canal	1,894,831
30	GM - Fiber	1,876,910
31	Etiwanda: Fully equip (1) 66 kV pos	1,844,775
32	SD-Digital Solutions Technology Fou	1,840,827
33	48- LS-1 CONVERSION PROJECT/LED REP	1,838,710
34	U_STORM:Ventura County- Thomas Fire	1,828,802
35	SCE.com Release 10 remaining SUP -	1,809,349
36	Valley Sub: Install On-Line DGA Equ	1,793,817
37	Valley Sub: Install PMUs	1,782,307
38	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,775,009
39	U_BAYSIDE-GISLER FO (03199) PROPOSE	1,770,470
40	Viejo: Replace 66kV line relays	1,757,770
41	Distributables 2018	1,749,650
42	x86 - Call Center	1,744,322
43	TOTAL	3,879,243,378

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DSP	1,742,678
2	CS-Vincent Sub-CIP 014 Program	1,739,240
3	Steel Pole Field Checks	1,738,459
4	U_LUGO-MIRA LOMA #2 F/W CABLE(08127	1,736,702
5	Midway-Vincent No1 500kV-TLRR	1,721,666
6	C&C Threat Intelligence Program	1,719,611
7	DSP	1,716,431
8	Villa Park Sub - Replace 18 CBs #:5	1,706,581
9	DH LH RELO OH CALTRANS - I-5 @ VALL	1,700,028
10	51 TULARE LS-1 LED PROJECT 2-2018	1,696,517
11	FIP-Lighthipe-Mesa: Install 3 strct	1,689,430
12	LA CIENEGA-CULVER 66KV RECABLE PIN	1,670,360
13	Alamitos NU Ph1: Install new 220kV	1,667,914
14	I5 WIDENING SEG 5 PROJECT ID 114	1,658,048
15	Bailey-Pardee:TLRR Remediation	1,642,667
16	SD-CCC IVR Upgrade - Phase 1 - CS	1,638,754
17	Carson Sub Phase I: Upgrade HMI as	1,634,207
18	Rector-Springville 220kV-TLRR	1,622,691
19	DSP DSP	1,602,549
20	Deferred - BC8 - High pressure pipi	1,601,035
21	Estrella Substation: SAS to SA3 Con	1,600,614
22	CFF-TARIFF-Whirlwind(IF):Instl pos	1,598,454
23	T&D Miscellaneous Equipment - Capit	1,590,370
24	LP Feedwater Heater Repl U3 Phase 1	1,588,623
25	SMOO-IBM WebSphere ESB Refresh	1,577,730
26	PVCC - PRA Model - Fire	1,577,303
27	DSP DSP2017 SEPULVEDA SUB ELIMINATI	1,567,581
28	2018 C&C Capital Tool APSN	1,564,624
29	NGT1-16ICatalinaBandwidthPebblyBchG	1,560,052
30	DSP	1,559,599
31	INFRASTRUCTURE REPLACEMENT (WORST C	1,554,500
32	Haiwee-Inyokern Segment TLRR	1,549,229
33	PLANT BETTERMENT/UPGRADING DISTRIBU	1,545,784
34	C&MS Full Replacement	1,536,745
35	TOT223 Devers-Install 4 reactor ban	1,514,599
36	TLRR-D-E-T-PTO83101	1,511,553
37	SD-EPCR - UI Re-Platform	1,511,338
38	CFF:ANTELOPE INSTALL ONLINE DISSOLV	1,509,808
39	U_Vestal -Delano FOC#11051 New CBL	1,504,883
40	CS-SERRANO SUB - Perimeter Security	1,500,892
41	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,492,037
42	Etiwanda Sub: Install OnLine DGA Eq	1,488,911
43	TOTAL	3,879,243,378

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Antlope-Big Sky:Instal 220kV Gen Ti	1,471,899
2	Whirlwind (IF):Instll line drop w C	1,458,229
3	TLRR PRI A2 4502353 (168)	1,456,151
4	INFRASTRUCTURE REPLACEMENT (WORST C	1,438,705
5	Lugo: Install new SPS relays and co	1,435,505
6	Gorman-Kern River 1 Segment TLRR	1,431,584
7	Digital Accelerator Mobile Apps	1,430,889
8	MidwayVincent2 TLRR Remediation Nr	1,419,191
9	Sullivan Rpl No4 Bank 66/12kV	1,418,522
10	ADDED FACILITIES ADDED FACILITIESTA	1,410,705
11	CS - Devers Sub Perimeter Security	1,407,112
12	Big Creek 3-Rector 1 TLRR Remediati	1,402,555
13	DH CS CH CAP ON RAMP RECABLE PHASE	1,400,397
14	Lynwood 16/4.16 (D) - Replace (4) 1	1,399,022
15	CFF~Red Bluff Substation (NU): Inst	1,397,886
16	U_01087_Tap to Fair Oaks Sub_EES	1,395,405
17	Lennox: Replace the No.1 + No.2 ban	1,386,098
18	Amador: Replace existing SAS with S	1,385,557
19	Mt. View Gen Station Refresh	1,383,891
20	PVCGP-Plant 2-Way Radio Replacement	1,383,169
21	DSP DSPPIF#746195 SUB ELIMINATION P	1,381,453
22	DSP	1,381,182
23	4703-0440--ET-NW-HIGHLAND* GOLDTOW	1,380,315
24	Pending Cancellation-Mira Loma-Vist	1,367,678
25	FIP-Eldorado-Mohave T/L: Instal OPG	1,361,045
26	El Nido-La Cienega 220kV-TLRR	1,358,301
27	Spent Fuel Pool Borated Inserts U2	1,347,517
28	CS - Covina SC Security Upgrade	1,345,186
29	DSP DSPSTIRRUP SUB IR-TRUDIE 4KV	1,341,411
30	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,333,293
31	SD-Perimeter Sec CIP14: App Phase 3	1,331,799
32	RULE 20A - UG INSTALL RULE 20A - UG	1,330,696
33	Serrano-Valley 500kV-San Jac-TLRR	1,328,455
34	Digital SMP Phase I	1,327,746
35	LINE EXTENSION LINE EXTENSIONMOCK O	1,325,341
36	Cadillac 12 kV Circuit % Narrows Su	1,317,375
37	FIP-Mesa: Upgrade to a 500/230/66/1	1,314,641
38	U_SONGS-VIEJO FW _03124)_FH	1,311,434
39	Eric Substation: SAS to SA3 Convers	1,306,881
40	RULE 20B - UG INSTALL RULE 20B - UG	1,305,490
41	MV- Install Storage Building	1,300,419
42	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,296,337
43	TOTAL	3,879,243,378

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DSP	1,296,186
2	Control-Haiwee:Rbuild tower/2 Lines	1,289,665
3	Pardee-Seismic-instl brace and spac	1,289,073
4	Ganesha Replace (29) 66/12kv CBs	1,285,026
5	FIP-Eldorado-Lugo T/L(CA): Clear in	1,273,368
6	INFRASTRUCTURE REPLACEMENT (WORST C	1,269,361
7	Moorpark Sub: Replace existing RTUs	1,265,884
8	Santa Clara: Replace (4) 220 KV Cir	1,256,662
9	LP Feedwater Heater Repl U1 Phase1	1,256,297
10	Pardee-Pastoria 220kV-North Cst-TLR	1,255,512
11	CT Life Extension 2018 U2	1,253,428
12	SC JS/LH STORM SAYRE FIRE CRIB WALL	1,253,147
13	LINE EXTENSION LINE EXTENSION	1,236,290
14	DSP	1,230,162
15	The Irvine Company - Misc Cap Act.	1,229,203
16	THURAM-16I-IR: Alamitos 220/66-Alam	1,228,297
17	Lighthipe-Replace No.1A Bank 220/66	1,225,838
18	BANDUCCI PIN 6619	1,223,295
19	VA-CONSTRUCT NEW 8 MI 115KV LINE FO	1,220,041
20	6000-9999-MONTHLY ACCOUNTS PAYABLE	1,218,855
21	DSP	1,211,830
22	CS - Victorrville S/C Upgrade	1,208,598
23	Arcadia Substation: Upgrade HMI/PLC	1,194,050
24	Kern River 1-Correction Segment TLR	1,191,873
25	SHEARIAE-09I-TRTP-HighwindSub	1,190,576
26	Build Spectrum Ring Cable-TIC 03216	1,190,559
27	NV Energy Magnolia-NSO 230 kV Line	1,185,619
28	AFUDC for CPUC Portion of 800063633	1,179,333
29	DSP	1,177,720
30	CAUDILJ-18I-18I-DR-ENT:RanchoCucamo	1,175,729
31	Hinson-Long Bech 66kV:Replace twrs&	1,168,932
32	Padua Sub: Install On-Line DGA Equi	1,166,410
33	PLANT BETTERMENT/UPGRADING DISTRIBU	1,166,087
34	R/R 1 DET POLES (822045E)	1,164,736
35	Const Power Replacement - 2014-16	1,161,022
36	DSP DSPPIF-627044 HILLTOP 4KV % SAN	1,160,942
37	Midway:Replace 4 sets discs on srs	1,160,022
38	Devers Sub: Install/wire/test the f	1,153,572
39	Correction-Cummings Segment TLRR	1,152,847
40	C&C Interior Defense TTNM - Phase I	1,148,884
41	Somerset: Rplc (2) 12 kV & (9) 4kv	1,147,650
42	SHEARIAE-11I-NtwkUp-Abengoa-WaterVa	1,145,849
43	TOTAL	3,879,243,378

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Chiquita Substation: SAS to SA3 Con	1,144,729
2	Santa Ana Bldg A - Seismic Upgrades	1,140,358
3	FIP-I:Highwind: Visual Mitigation M	1,140,216
4	Somerset Substation: SAS to SA3 Con	1,140,199
5	RULE 20A - UG INSTALL RULE 20A - UG	1,139,389
6	DSP	1,138,931
7	Edwards Sub: Rpl No1 Bank	1,136,171
8	DSP DSPNEW DSP CIRCUIT CAROON % MAR	1,129,009
9	BSH-Bishop Creek Relicensing	1,122,331
10	GCC Alhambra: Install 5 servers	1,122,004
11	PREVENTIVE MAINT (ELECTIVE OPTION)	1,119,323
12	DSP DSPPIF 846042, BUNDLED PROJECT	1,113,758
13	8456-0697--KRAMER HOLGATE FO CCR PR	1,112,697
14	2018 C&C Password Vault Update II	1,110,276
15	PLANT BETTERMENT OUTSOURCE 555 9/19	1,104,283
16	PLANT BETTERMENT/UPGRADING DISTRIBU	1,103,298
17	Fernwood Sub: Install 2 Groundbanks	1,096,523
18	SD-Pega agreement-COE for RPA/BMP	1,096,377
19	Imperial Substation: SAS to SA3 Con	1,094,283
20	44 ADDED FACILITIES ADDED FACILITIE	1,092,787
21	SD - WM Dashboard	1,091,711
22	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,091,082
23	License Renewal - Update Project	1,089,963
24	U_PISGAH-GALE F.O. CABLE (08077)	1,088,332
25	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,087,950
26	U_FOC Refresh Eaglerock-Pardee-Sylm	1,086,121
27	Kramer-Coolwater Segment TLRR	1,081,991
28	Whirlwind-Install relays, CRAS, SEL	1,081,417
29	5137-8201--CYBER SUB: INSTALL A NEW	1,076,954
30	Magnastor Dry Cask Storage	1,076,844
31	RadiantLogic VDS ICS Upgrade	1,066,045
32	RattleSnake-Whirlwind(IF):Instll Ge	1,063,973
33	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,062,523
34	2017/2018 SAP Database Encryption	1,061,197
35	ECS Capital CRM Related Software Li	1,055,283
36	Ellis Substation (RLA Facilities -	1,053,632
37	Latigo Sub: Rplc 66/12kV Xfmr Bank	1,053,452
38	Magunden: Install necessary phasor	1,047,169
39	T&D Drive School & Crane Cert Relo	1,043,164
40	RELOCATE FACILITIES RELOCATE FACILI	1,041,860
41	Main Transformer Repl 2R21	1,032,237
42	INFRASTRUCTURE REPLACEMENT (CONDUCT	1,031,894
43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DSP DSP2018 DSP - CONDOR % BANDUCCI	1,026,496
2	CS-Alhambra Data Center-CIP 014 Pro	1,026,251
3	DSP DSP843044 IRON 12KV % LIMESTONE	1,023,061
4	CS - NERC CIP V6 PSM Low Impact Pro	1,019,495
5	Lennox Sub: Add a Transformer 66/16	1,017,616
6	Potrero:Upgrade Equipment <(>&<)> E	1,016,803
7	Control-Coso Segment TLRR	1,015,975
8	Coso-Haiwee Segment TLRR	1,015,975
9	Haiwee-Inyokern Segment TLRR	1,015,975
10	SP T&D SERA Asmt Trans Lines & Dis	1,014,073
11	51 HANFORD LS-1 LED PROJECT 2-2018	1,013,200
12	GRID MODERNIZATION	1,013,153
13	GM - GAA - Weather Data	1,008,692
14	Tortilla Substation (IF): Construct	1,005,753
15	WORK ORDERS UNDER $1,000,000	1,184,307,367
16	Rounding	-1
17		
18		
19		
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43	TOTAL	3,879,243,378

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	12,936,416,577	12,936,416,577		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,645,968,668	1,645,968,668		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,278,751	1,278,751		
7	Other Clearing Accounts	9,682,814	9,682,814		
8	Other Accounts (Specify, details in footnote):	2,719,161	2,719,161		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,659,649,394	1,659,649,394		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	744,766,343	744,766,343		
13	Cost of Removal	702,865,169	702,865,169		
14	Salvage (Credit)	74,726,644	74,726,644		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	1,372,904,868	1,372,904,868		
16	Other Debit or Cr. Items (Describe, details in footnote):	41,701,694	41,701,694		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	13,264,862,797	13,264,862,797		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	189,650	189,650		
21	Nuclear Production	1,615,298,914	1,615,298,914		
22	Hydraulic Production-Conventional	502,203,508	502,203,508		
23	Hydraulic Production-Pumped Storage				
24	Other Production	606,239,611	606,239,611		
25	Transmission	2,658,479,371	2,658,479,371		
26	Distribution	6,821,799,320	6,821,799,320		
27	Regional Transmission and Market Operation				
28	General	1,060,652,423	1,060,652,423		
29	TOTAL (Enter Total of lines 20 thru 28)	13,264,862,797	13,264,862,797		

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

Amortization. Change in Ratemaking Decommissioning Liability.

Schedule Page: 219 Line No.: 12 Column: c

Retirements not in account 108

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	Mono Power Company			
2	Capital Stock	03/02/70	none	100
3	Additional Paid-in Capital	03/02/70	none	2,749,150
4	Undistributed Earnings			-2,672,349
5				
6	Southern States Realty			
7	Capital Stock	01/22/73	none	100
8	Additional Paid-in Capital	01/22/73	none	
9	Undistributed Earnings			68,867
10				
11	Rounding			1
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
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41				
42	Total Cost of Account 123.1 $ 2,749,350		TOTAL	145,869

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		100		2
		2,749,150		3
-626		-2,672,975		4
				5
				6
		100		7
				8
		68,867		9
				10
				11
				12
				13
				14
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-626		145,242		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	3,662,961	2,683,058	
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)	204,749,774	256,851,474	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	18,287,333	13,999,088	
8	Transmission Plant (Estimated)	1,301,694	714,918	
9	Distribution Plant (Estimated)	12,052,598	7,280,145	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,615,342	820,399	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	238,006,741	279,666,024	
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)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	241,669,702	282,349,082	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2019 No. (d)	2019 Amt. (e)
1	Balance-Beginning of Year	489,240.00	1,152,248	289,632.00	562,915
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	NOx				
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	116,351.00	325,883		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Excess V2018 to FMV		166,968		
23	Transfer to Catalina	60,000.00	123,600		
24	Expired NOx	63,344.00	36,705		
25	True-Up	56.00	115		
26					
27					
28	Total	123,400.00	327,388		
29	Balance-End of Year	249,489.00	498,977	289,632.00	562,915
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2020		2021		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
289,632.00	535,534	289,632.00	509,522	1,929,494.00	2,930,127	3,287,630.00	5,690,346	1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						116,351.00	325,883	18
								19
								20
								21
							166,968	22
						60,000.00	123,600	23
						63,344.00	36,705	24
						56.00	115	25
								26
								27
						123,400.00	327,388	28
289,632.00	535,534	289,632.00	509,522	1,929,494.00	2,930,127	3,047,879.00	5,037,075	29
								30
								31
								32
								33
								34
								35
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								37
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								39
								40
								41
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								46

Schedule Page: 229 Line No.: 1 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line on page 110. Difference is due to $7,046,214 in GHG Allowances.

Schedule Page: 229 Line No.: 29 Column: m

Total ending balance of account 158.1 per this page does not agree to the corresponding balance sheet line on page 110. Difference is due to $9,611,244 in GHG Allowances.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	SONGS Settlement	71,555,000	-71,555,000	407		
22	D18-08-007					
23						
24						
25	Palo Verde Nuclear Generating	533,998		407	-18,682	515,316
26	Station over the authorized					
27	License Term January 1989 to					
28	July 2046					
29						
30						
31	Mohave Generating Station Plant	-2,254,446	2,408,634	407		154,188
32	over the authorized License Term					
33	January 2006 to June 2016					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL	69,834,552	-69,146,366		-18,682	669,504

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Interconnection Studies	(74,394)	143	147,963	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	3,811,273	143	(5,438,392)	143
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Schedule Page: 231 Line No.: 2 Column: a

Project Type	Project Description	Costs Incurred	Account Charged	Reimbursements	Account Credited
Transmission	800063881 Interconnnection Study	$ -	143	$ (37,481.18)	143
Transmission	800063994 Interconnnection Study	169.92	143	(1,444.64)	143
Transmission	800063997 Interconnnection Study	(138.55)	143	57,670.32	143
Transmission	800064007 Interconnnection Study	(46.72)	143	(39,966.52)	143
Transmission	800064039 Interconnnection Study	(107.08)	143	(2,456.61)	143
Transmission	800064061 Interconnnection Study	(3,329.41)	143	7,804.04	143
Transmission	800064066 Interconnnection Study	(672.75)	143	60,188.63	143
Transmission	800064148 Interconnnection Study	246.43	143	9,097.41	143
Transmission	800064152 Interconnnection Study	(342.16)	143	7,389.21	143
Transmission	800064473 Interconnnection Study	259.64	143	8,426.23	143
Transmission	800064508 Interconnnection Study	143.05	143	13,621.92	143
Transmission	800143449 Interconnnection Study	3,153.11	143	17,224.53	143
Transmission	800250922 Interconnnection Study	10,753.83	143	-	143
Transmission	800293812 Interconnnection Study	(120,388.14)	143	12,562.83	143
Transmission	900835355 Interconnnection Study	639.27	143	69,226.24	143
Transmission	901131640 Interconnnection Study	2,491.45	143	1,100.71	143
Transmission	901833427 Interconnnection Study	22,213.70	143	-	143
Transmission	902331315 Interconnnection Study	10,560.86	143	(35,000.00)	143
	TOTAL TRANSMISSION	**$ (74,393.55)**		**$ 147,963.12**	

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

Column (b) may not include A and G expenses for the period.

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

Column (d) includes refunds that were paid to the Interconnection customer in 2018 resulting from payment 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	Project Description	Costs Incurred	Account Charged	Reimbursements	Account Credited
Generation	800063826 Interconnnection Study	$ -	143	$ (1,141.55)	143
Generation	800063828 Interconnnection Study		143	-	143
Generation	800063831 Interconnnection Study		143	(35,048.85)	143
Generation	800063850 Interconnnection Study	(604.76)	143	30,499.03	143
Generation	800063931 Interconnnection Study	1,772.52	143	15,690.81	143
Generation	800064060 Interconnnection Study	983.57	143	(2,485.54)	143
Generation	800064101 Interconnnection Study		143	4,858.12	143
Generation	800064113 Interconnnection Study	(274.18)	143	(11,220.93)	143
Generation	800064117 Interconnnection Study	2,191.45	143	(5,449.59)	143
Generation	800064119 Interconnnection Study		143	(16,037.37)	143
Generation	800064125 Interconnnection Study	(8.31)	143	(2,444.30)	143
Generation	800064139 Interconnnection Study	(58.49)	143	-	143
Generation	800064150 Interconnnection Study	(60.13)	143	8,458.78	143
Generation	800064163 Interconnnection Study	(577.73)	143	27,461.89	143
Generation	800064164 Interconnnection Study	(418.78)	143	-	143
Generation	800064165 Interconnnection Study	15,875.56	143	(177,042.10)	143
Generation	800064171 Interconnnection Study	(187.26)	143	22,437.28	143
Generation	800064207 Interconnnection Study	(246.15)	143	39,212.42	143
Generation	800064208 Interconnnection Study	(538.31)	143	93,474.25	143
Generation	800064258 Interconnnection Study	(609.88)	143	-	143

Generation	800064274 Interconnnection Study	(253.77)	143	89,109.02	143
Generation	800064327 Interconnnection Study	(296.48)	143	29,006.49	143
Generation	800064390 Interconnnection Study		143	-	143
Generation	800064440 Interconnnection Study	72.41	143	9,384.38	143
Generation	800064489 Interconnnection Study	360.34	143	5,508.61	143
Generation	800064514 Interconnnection Study	(11.55)	143	10,717.95	143
Generation	800064565 Interconnnection Study	32.21	143	9,016.74	143
Generation	800064572 Interconnnection Study	(14.65)	143	-	143
Generation	800064599 Interconnnection Study	(6.55)	143	40,787.79	143
Generation	800064616 Interconnnection Study	897.58	143	41,663.93	143
Generation	800064621 Interconnnection Study	41.88	143	9,607.69	143
Generation	800064711 Interconnnection Study	11.48	143	49,904.89	143
Generation	800121940 Interconnnection Study	91.54	143	25,315.14	143
Generation	800131402 Interconnnection Study	9.50	143	9,966.94	143
Generation	800131403 Interconnnection Study	9.50	143	-	143
Generation	800170532 Interconnnection Study	987.03	143	24,989.96	143
Generation	800216376 Interconnnection Study	(291.22)	143	191,821.18	143
Generation	800216400 Interconnnection Study	(340.38)	143	202,033.17	143
Generation	800216402 Interconnnection Study	(340.38)	143	-	143
Generation	800217401 Interconnnection Study	(946.78)	143	159,540.89	143
Generation	800492446 Interconnnection Study		143	-	143
Generation	900197522 Interconnnection Study	(5,336.54)	143	-	143
Generation	900197523 Interconnnection Study	2,525.89	143	(12,852.44)	143
Generation	900225715 Interconnnection Study	(20,484.23)	143	(85,311.34)	143
Generation	900225716 Interconnnection Study	(8,744.45)	143	(82,205.88)	143
Generation	900225717 Interconnnection Study	(8,523.56)	143	-	143
Generation	900225718 Interconnnection Study	(8,804.74)	143	(64,919.93)	143
Generation	900242335 Interconnnection Study	635.23	143	51,776.90	143
Generation	900242336 Interconnnection Study	(14,110.70)	143	-	143
Generation	900242341 Interconnnection Study		143	41,879.74	143
Generation	900268228 Interconnnection Study	134.17	143	519.66	143
Generation	900268273 Interconnnection Study	(194.83)	143	39,994.68	143
Generation	900363113 Interconnnection Study	(1.00)	143	41,846.45	143
Generation	900363285 Interconnnection Study	14,110.70	143	-	143
Generation	900363296 Interconnnection Study	(244.21)	143	43,444.06	143
Generation	900410673 Interconnnection Study	598.07	143	7,277.26	143
Generation	900410680 Interconnnection Study	463.86	143	7,981.53	143
Generation	900410681 Interconnnection Study	40.02	143	9,510.17	143
Generation	900410682 Interconnnection Study	42.62	143	9,441.95	143
Generation	900410683 Interconnnection Study	10.78	143	9,499.95	143
Generation	900410684 Interconnnection Study	26.82	143	9,208.56	143
Generation	900426595 Interconnnection Study	738.32	143	48,655.40	143
Generation	900439720 Interconnnection Study	377.65	143	(11,243.38)	143
Generation	900439728 Interconnnection Study	(371.50)	143	106,789.72	143
Generation	900439733 Interconnnection Study	(494.38)	143	39,529.58	143
Generation	900547651 Interconnnection Study	10.60	143	149,876.50	143
Generation	900572336 Interconnnection Study	166.86	143	(1,180.61)	143
Generation	900593362 Interconnnection Study	616.48	143	(7,608.33)	143
Generation	900676295 Interconnnection Study	(137.28)	143	1,909.06	143
Generation	900718712 Interconnnection Study		143	(54,364.79)	143
Generation	900751479 Interconnnection Study	19.62	143	1,527.05	143
Generation	901002470 Interconnnection Study	11,374.83	143	(6,311.94)	143
Generation	901037140 Interconnnection Study	7,643.00	143	7,380.67	143
Generation	901070520 Interconnnection Study	1,323.15	143	96,389.89	143
Generation	901070524 Interconnnection Study	(549.78)	143	158,643.54	143
Generation	901267948 Interconnnection Study	13,804.00	143	(88,521.33)	143
Generation	901276882 Interconnnection Study	1,230.27	143	15,498.71	143
Generation	901284713 Interconnnection Study	7,960.06	143	15,107.43	143

Generation	901284957 Interconnnection Study	1,383.13	143	-	143
Generation	901374472 Interconnnection Study	1,084.46	143	44,863.65	143
Generation	901397052 Interconnnection Study	88.76	143	1,305.37	143
Generation	901397053 Interconnnection Study	62.18	143	1,645.18	143
Generation	901397054 Interconnnection Study	30.98	143	2,119.08	143
Generation	901397056 Interconnnection Study	63.29	143	1,661.83	143
Generation	901397057 Interconnnection Study	67.69	143	1,639.15	143
Generation	901397058 Interconnnection Study	27.23	143	2,166.51	143
Generation	901397282 Interconnnection Study	191.27	143	126.06	143
Generation	901397283 Interconnnection Study	62.18	143	1,645.18	143
Generation	901397285 Interconnnection Study	174.65	143	359.23	143
Generation	901397287 Interconnnection Study	64.47	143	1,271.26	143
Generation	901397288 Interconnnection Study	65.82	143	1,204.56	143
Generation	901397289 Interconnnection Study	41.38	143	1,463.09	143
Generation	901397291 Interconnnection Study	53.16	143	1,419.52	143
Generation	901397292 Interconnnection Study	320.77	143	(1,791.49)	143
Generation	901483643 Interconnnection Study	1,764.52	143	33,483.03	143
Generation	901501005 Interconnnection Study		143	5,703.29	143
Generation	901502837 Interconnnection Study	342.66	143	5,373.10	143
Generation	901511986 Interconnnection Study	57.40	143	9,018.73	143
Generation	901513080 Interconnnection Study	321.29	143	5,751.07	143
Generation	901532782 Interconnnection Study	12,634.24	143	(75,893.33)	143
Generation	901532791 Interconnnection Study	9,458.07	143	(65,097.51)	143
Generation	901532800 Interconnnection Study	12,574.68	143	(74,559.98)	143
Generation	901532801 Interconnnection Study	12,684.00	143	(76,789.51)	143
Generation	901532802 Interconnnection Study	12,631.65	143	-	143
Generation	901532855 Interconnnection Study	5,578.29	143	35,189.09	143
Generation	901532856 Interconnnection Study	5,416.72	143	36,193.16	143
Generation	901534761 Interconnnection Study	195.19	143	64,452.47	143
Generation	901535370 Interconnnection Study	5,613.52	143	52,540.46	143
Generation	901551294 Interconnnection Study	5,141.87	143	13,746.53	143
Generation	901551295 Interconnnection Study	5,651.34	143	10,327.05	143
Generation	901551296 Interconnnection Study	5,575.58	143	10,002.18	143
Generation	901551710 Interconnnection Study	5,976.42	143	-	143
Generation	901551711 Interconnnection Study	5,939.81	143	21,186.21	143
Generation	901551713 Interconnnection Study	5,522.51	143	24,694.25	143
Generation	901586548 Interconnnection Study		143	10,000.00	143
Generation	901588137 Interconnnection Study	19.73	143	9,756.86	143
Generation	901588138 Interconnnection Study		143	10,000.00	143
Generation	901631980 Interconnnection Study	16.16	143	9,737.62	143
Generation	901631981 Interconnnection Study		143	10,000.00	143
Generation	901637742 Interconnnection Study	514.80	143	2,181.53	143
Generation	901641780 Interconnnection Study	170.86	143	-	143
Generation	901647076 Interconnnection Study	15.97	143	2,296.44	143
Generation	901647077 Interconnnection Study	15.97	143	2,296.44	143
Generation	901647078 Interconnnection Study	32.71	143	2,060.26	143
Generation	901647159 Interconnnection Study	34.64	143	2,058.33	143
Generation	901649251 Interconnnection Study	58.26	143	1,490.67	143
Generation	901649252 Interconnnection Study	57.39	143	1,489.77	143
Generation	901649254 Interconnnection Study	25.74	143	1,960.02	143
Generation	901650664 Interconnnection Study	31.95	143	2,062.95	143
Generation	901650665 Interconnnection Study	2.97	143	2,439.47	143
Generation	901650666 Interconnnection Study	50.99	143	1,807.33	143
Generation	901650667 Interconnnection Study	14.97	143	2,291.17	143
Generation	901673449 Interconnnection Study	777.84	143	(1,766.25)	143
Generation	901677974 Interconnnection Study	387.02	143	-	143
Generation	901742354 Interconnnection Study	124.27	143	7,813.77	143
Generation	901758968 Interconnnection Study	28.71	143	9,509.34	143

Generation	901758970 Interconnnection Study	14.35	143	9,754.68	143
Generation	901758971 Interconnnection Study		143	10,000.00	143
Generation	901758975 Interconnnection Study	14.35	143	9,754.68	143
Generation	901825476 Interconnnection Study	5,920.60	143	52,891.12	143
Generation	901832877 Interconnnection Study	7,222.49	143	29,696.68	143
Generation	901833796 Interconnnection Study	(14,254.02)	143	-	143
Generation	901834223 Interconnnection Study	12,842.14	143	-	143
Generation	901834436 Interconnnection Study	213.55	143	60,099.32	143
Generation	901834498 Interconnnection Study	5,008.15	143	(28,825.49)	143
Generation	901840826 Interconnnection Study	99.64	143	93,003.44	143
Generation	901847324 Interconnnection Study	146.85	143	(2,647.06)	143
Generation	901847886 Interconnnection Study	327.67	143	(4,806.46)	143
Generation	901854254 Interconnnection Study	4,845.91	143	(28,318.96)	143
Generation	901854256 Interconnnection Study	4,860.95	143	(27,845.25)	143
Generation	901854258 Interconnnection Study	5,129.04	143	(37,527.32)	143
Generation	901854619 Interconnnection Study	5,491.07	143	-	143
Generation	901854620 Interconnnection Study	5,261.03	143	(37,437.12)	143
Generation	901854622 Interconnnection Study	4,844.67	143	(33,176.30)	143
Generation	901854623 Interconnnection Study	4,816.29	143	(33,176.21)	143
Generation	901854624 Interconnnection Study	5,045.76	143	(33,187.61)	143
Generation	901880681 Interconnnection Study	332.39	143	2,958.03	143
Generation	901888772 Interconnnection Study		143	47,812.38	143
Generation	901888773 Interconnnection Study		143	55,345.32	143
Generation	901889094 Interconnnection Study	149.83	143	-	143
Generation	901889597 Interconnnection Study	2,259.15	143	14,551.96	143
Generation	901904490 Interconnnection Study	147.16	143	60,413.84	143
Generation	901965267 Interconnnection Study	23.85	143	2,144.11	143
Generation	902002842 Interconnnection Study	666.90	143	(3,776.14)	143
Generation	902027704 Interconnnection Study	1,000.91	143	47,083.76	143
Generation	902032905 Interconnnection Study	12,842.14	143	-	143
Generation	902046153 Interconnnection Study	11,527.87	143	(20,648.76)	143
Generation	902089514 Interconnnection Study	8,292.78	143	-	143
Generation	902093692 Interconnnection Study	120.32	143	8,155.70	143
Generation	902094856 Interconnnection Study	6,034.63	143	-	143
Generation	902094857 Interconnnection Study	14,842.09	143	-	143
Generation	902100313 Interconnnection Study	2,535.19	143	-	143
Generation	902110832 Interconnnection Study	7,817.26	143	-	143
Generation	902114963 Interconnnection Study	3,833.72	143	(20,743.16)	143
Generation	902114965 Interconnnection Study	5,723.57	143	(22,444.03)	143
Generation	902114966 Interconnnection Study	2,350.81	143	(12,489.55)	143
Generation	902114969 Interconnnection Study	3,906.85	143	(21,768.30)	143
Generation	902114970 Interconnnection Study	5,250.53	143	(22,873.77)	143
Generation	902114971 Interconnnection Study	4,346.90	143	(20,882.22)	143
Generation	902114972 Interconnnection Study	4,326.79	143	(20,605.15)	143
Generation	902114973 Interconnnection Study	4,353.70	143	(20,975.92)	143
Generation	902115234 Interconnnection Study	4,350.13	143	(21,140.61)	143
Generation	902115236 Interconnnection Study	3,910.97	143	(20,844.85)	143
Generation	902115237 Interconnnection Study	3,936.33	143	(21,376.10)	143
Generation	902115238 Interconnnection Study	3,941.05	143	(21,072.89)	143
Generation	902115282 Interconnnection Study	3,829.29	143	(21,927.07)	143
Generation	902115283 Interconnnection Study	5,322.05	143	(21,760.39)	143
Generation	902115381 Interconnnection Study	2,254.72	143	(12,196.93)	143
Generation	902115862 Interconnnection Study	5,236.32	143	898.98	143
Generation	902115863 Interconnnection Study	3,841.12	143	1,866.35	143
Generation	902119157 Interconnnection Study	139.82	143	57,937.06	143
Generation	902120276 Interconnnection Study	13,371.68	143	-	143
Generation	902120277 Interconnnection Study	385.32	143	66,954.06	143
Generation	902124363 Interconnnection Study	114.05	143	(1,688.64)	143

Generation	902124364 Interconnnection Study	79.05	143	(1,171.95)	143
Generation	902124365 Interconnnection Study	74.08	143	(1,097.85)	143
Generation	902125654 Interconnnection Study	919.33	143	-	143
Generation	902125793 Interconnnection Study	14,239.47	143	-	143
Generation	902128480 Interconnnection Study	1,864.50	143	55,175.55	143
Generation	902128488 Interconnnection Study	11,696.36	143	-	143
Generation	902128489 Interconnnection Study	16,441.60	143	-	143
Generation	902128491 Interconnnection Study	11,484.95	143	-	143
Generation	902128492 Interconnnection Study	11,305.98	143	-	143
Generation	902128493 Interconnnection Study	13,393.69	143	-	143
Generation	902128695 Interconnnection Study	13,658.96	143	-	143
Generation	902128696 Interconnnection Study	13,397.06	143	-	143
Generation	902128813 Interconnnection Study	15,054.66	143	-	143
Generation	902128814 Interconnnection Study	13,711.72	143	-	143
Generation	902128815 Interconnnection Study	206.49	143	59,677.89	143
Generation	902128819 Interconnnection Study	378.74	143	65,597.30	143
Generation	902129080 Interconnnection Study	14,422.22	143	-	143
Generation	902129081 Interconnnection Study	15,515.68	143	-	143
Generation	902129082 Interconnnection Study	14,245.62	143	-	143
Generation	902129134 Interconnnection Study	15,090.42	143	-	143
Generation	902129349 Interconnnection Study	292.36	143	57,924.85	143
Generation	902132671 Interconnnection Study	13,127.19	143	-	143
Generation	902132730 Interconnnection Study	13,718.76	143	-	143
Generation	902132732 Interconnnection Study	967.93	143	-	143
Generation	902132733 Interconnnection Study	769.88	143	-	143
Generation	902132734 Interconnnection Study	1,203.59	143	-	143
Generation	902132735 Interconnnection Study	331.58	143	-	143
Generation	902132736 Interconnnection Study	14,918.90	143	-	143
Generation	902132737 Interconnnection Study	13,536.75	143	-	143
Generation	902132738 Interconnnection Study	3,800.07	143	-	143
Generation	902132839 Interconnnection Study	473.91	143	98,225.34	143
Generation	902132840 Interconnnection Study	13,781.63	143	-	143
Generation	902132841 Interconnnection Study	13,441.13	143	-	143
Generation	902133250 Interconnnection Study	17,364.69	143	-	143
Generation	902133251 Interconnnection Study	527.06	143	87,051.10	143
Generation	902133527 Interconnnection Study	1,487.87	143	-	143
Generation	902133529 Interconnnection Study	660.39	143	-	143
Generation	902133535 Interconnnection Study	19,828.78	143	45,753.33	143
Generation	902133537 Interconnnection Study	1,139.93	143	-	143
Generation	902133538 Interconnnection Study	152.05	143	-	143
Generation	902133604 Interconnnection Study	15,910.69	143	-	143
Generation	902133605 Interconnnection Study	1,550.93	143	-	143
Generation	902133606 Interconnnection Study	2,233.17	143	-	143
Generation	902133607 Interconnnection Study	1,153.52	143	-	143
Generation	902133608 Interconnnection Study	1,343.29	143	-	143
Generation	902133609 Interconnnection Study	2,067.39	143	-	143
Generation	902133611 Interconnnection Study	552.83	143	-	143
Generation	902133675 Interconnnection Study	13,404.94	143	-	143
Generation	902133728 Interconnnection Study	925.75	143	-	143
Generation	902133729 Interconnnection Study	1,295.39	143	-	143
Generation	902133730 Interconnnection Study	1,531.39	143	-	143
Generation	902133732 Interconnnection Study	60.33	143	94,297.71	143
Generation	902133733 Interconnnection Study	14,457.76	143	-	143
Generation	902133734 Interconnnection Study	12,946.89	143	-	143
Generation	902133735 Interconnnection Study	12,547.76	143	-	143
Generation	902133901 Interconnnection Study	1,478.30	143	-	143
Generation	902133902 Interconnnection Study	1,322.09	143	-	143
Generation	902133904 Interconnnection Study	1,078.90	143	-	143

Generation	902133905 Interconnnection Study	2,092.38	143	-	143
Generation	902133906 Interconnnection Study	1,633.10	143	-	143
Generation	902136377 Interconnnection Study	13,094.03	143	-	143
Generation	902136440 Interconnnection Study	13,173.04	143	-	143
Generation	902136442 Interconnnection Study	13,329.10	143	-	143
Generation	902136444 Interconnnection Study	12,914.07	143	-	143
Generation	902136445 Interconnnection Study	111.48	143	-	143
Generation	902136446 Interconnnection Study	13,141.45	143	-	143
Generation	902136562 Interconnnection Study	2,125.53	143	-	143
Generation	902136564 Interconnnection Study	12,954.15	143	-	143
Generation	902136565 Interconnnection Study	13,102.07	143	-	143
Generation	902136566 Interconnnection Study	13,774.32	143	-	143
Generation	902136567 Interconnnection Study	13,098.97	143	-	143
Generation	902136796 Interconnnection Study	3,779.13	143	(21,141.91)	143
Generation	902136797 Interconnnection Study	5,436.48	143	(22,593.03)	143
Generation	902136798 Interconnnection Study	3,923.76	143	(20,649.00)	143
Generation	902136840 Interconnnection Study	3,915.61	143	(21,145.37)	143
Generation	902136841 Interconnnection Study	4,098.58	143	(21,396.89)	143
Generation	902136842 Interconnnection Study	5,683.38	143	(22,185.17)	143
Generation	902136843 Interconnnection Study	5,450.07	143	(22,073.64)	143
Generation	902136844 Interconnnection Study	4,066.53	143	(20,586.62)	143
Generation	902136845 Interconnnection Study	3,751.46	143	(20,364.62)	143
Generation	902136846 Interconnnection Study	4,224.24	143	(20,672.31)	143
Generation	902145768 Interconnnection Study	378.70	143	(5,601.57)	143
Generation	902149666 Interconnnection Study	674.98	143	8,628.31	143
Generation	902159135 Interconnnection Study	318.89	143	-	143
Generation	902162231 Interconnnection Study	530.30	143	-	143
Generation	902162483 Interconnnection Study	466.22	143	-	143
Generation	902167760 Interconnnection Study	1,059.82	143	49,556.74	143
Generation	902168990 Interconnnection Study	8,499.38	143	(21,899.91)	143
Generation	902168993 Interconnnection Study	7,873.04	143	(21,279.15)	143
Generation	902168995 Interconnnection Study	8,675.69	143	(22,067.35)	143
Generation	902168996 Interconnnection Study	7,281.69	143	(20,857.19)	143
Generation	902168997 Interconnnection Study	8,092.12	143	(21,473.45)	143
Generation	902169119 Interconnnection Study	8,446.90	143	(21,841.98)	143
Generation	902169120 Interconnnection Study	11,460.89	143	(25,300.98)	143
Generation	902169121 Interconnnection Study	6,176.30	143	(19,656.87)	143
Generation	902169123 Interconnnection Study	13,137.17	143	(26,325.94)	143
Generation	902169124 Interconnnection Study	10,031.30	143	(23,420.94)	143
Generation	902169125 Interconnnection Study	9,110.86	143	(23,107.97)	143
Generation	902169126 Interconnnection Study	9,799.82	143	(23,122.68)	143
Generation	902169128 Interconnnection Study	8,041.71	143	(21,448.07)	143
Generation	902169180 Interconnnection Study	7,820.73	143	(21,514.52)	143
Generation	902169182 Interconnnection Study	9,276.49	143	(23,875.49)	143
Generation	902169183 Interconnnection Study	7,401.43	143	(20,825.97)	143
Generation	902169184 Interconnnection Study	7,567.69	143	(21,421.51)	143
Generation	902169188 Interconnnection Study	9,199.35	143	(22,696.20)	143
Generation	902169234 Interconnnection Study	9,228.30	143	(22,714.74)	143
Generation	902169237 Interconnnection Study	10,801.24	143	(24,085.44)	143
Generation	902169238 Interconnnection Study	6,036.94	143	(13,312.74)	143
Generation	902169259 Interconnnection Study	8,286.48	143	(21,677.40)	143
Generation	902169261 Interconnnection Study	10,260.43	143	(23,999.34)	143
Generation	902169262 Interconnnection Study	8,128.71	143	(21,531.94)	143
Generation	902169266 Interconnnection Study	6,247.74	143	(13,526.47)	143
Generation	902188964 Interconnnection Study	397.19	143	-	143
Generation	902195789 Interconnnection Study	32.32	143	(537.55)	143
Generation	902204874 Interconnnection Study	345.38	143	(5,613.80)	143
Generation	902223125 Interconnnection Study	218.57	143	9,797.89	143

Generation	902228663 Interconnnection Study	13,238.30	143	-	143
Generation	902238794 Interconnnection Study	11,793.50	143	-	143
Generation	902238795 Interconnnection Study	434.06	143	-	143
Generation	902238933 Interconnnection Study	374.42	143	-	143
Generation	902254346 Interconnnection Study	5,377.73	143	(6,799.43)	143
Generation	902254475 Interconnnection Study	448.16	143	(10,000.00)	143
Generation	902263072 Interconnnection Study	164.48	143	(2,155.88)	143
Generation	902291277 Interconnnection Study	301.80	143	(592.80)	143
Generation	902291278 Interconnnection Study	4,862.31	143	-	143
Generation	902298981 Interconnnection Study	3,725.23	143	-	143
Generation	902301626 Interconnnection Study	30,469.81	143	(70,000.00)	143
Generation	902301924 Interconnnection Study	19,746.73	143	(69,000.00)	143
Generation	902305815 Interconnnection Study	26,850.51	143	(150,000.00)	143
Generation	902307066 Interconnnection Study	550.94	143	(10,000.00)	143
Generation	902311001 Interconnnection Study	1,868.78	143	(1,793.93)	143
Generation	902311002 Interconnnection Study	136,981.81	143	-	143
Generation	902327492 Interconnnection Study	2,264.39	143	(2,178.59)	143
Generation	902327493 Interconnnection Study	1,875.41	143	(1,808.55)	143
Generation	902327560 Interconnnection Study	1,875.41	143	(1,808.55)	143
Generation	902331090 Interconnnection Study	3,511.82	143	(3,358.27)	143
Generation	902331316 Interconnnection Study	2,498.14	143	(2,390.17)	143
Generation	902332343 Interconnnection Study	8,853.06	143	(10,000.00)	143
Generation	902337786 Interconnnection Study	388.93	143	(369.99)	143
Generation	902338265 Interconnnection Study	18,692.31	143	(120,000.00)	143
Generation	902343304 Interconnnection Study	3,879.28	143	(1,634.07)	143
Generation	902343306 Interconnnection Study	19,294.38	143	(81,000.00)	143
Generation	902343307 Interconnnection Study	3,469.14	143	(1,230.37)	143
Generation	902343308 Interconnnection Study	7,552.03	143	(6,107.85)	143
Generation	902343311 Interconnnection Study	18,372.32	143	(64,000.00)	143
Generation	902343398 Interconnnection Study	28,947.51	143	(72,000.00)	143
Generation	902343576 Interconnnection Study	2,025.30	143	(1,934.48)	143
Generation	902348666 Interconnnection Study	19,557.15	143	(100,000.00)	143
Generation	902349497 Interconnnection Study	9,248.75	143	(51,000.00)	143
Generation	902354856 Interconnnection Study	2,606.68	143	(10,000.00)	143
Generation	902369517 Interconnnection Study	159.80	143	(10,000.00)	143
Generation	902369760 Interconnnection Study	1,379.09	143	(10,000.00)	143
Generation	902370582 Interconnnection Study	1,844.73	143	-	143
Generation	902377012 Interconnnection Study	18,284.92	143	(60,000.00)	143
Generation	902377014 Interconnnection Study	18,270.49	143	(60,000.00)	143
Generation	902377017 Interconnnection Study	18,672.63	143	(60,000.00)	143
Generation	902377162 Interconnnection Study	168.94	143	1,074.76	143
Generation	902377371 Interconnnection Study	21,281.85	143	(250,000.00)	143
Generation	902377647 Interconnnection Study	19,038.97	143	(80,000.00)	143
Generation	902381580 Interconnnection Study	27,485.15	143	(150,000.00)	143
Generation	902381581 Interconnnection Study	19,345.26	143	(60,000.00)	143
Generation	902381584 Interconnnection Study	20,797.76	143	(60,000.00)	143
Generation	902382238 Interconnnection Study	23,277.37	143	(122,000.00)	143
Generation	902382507 Interconnnection Study	19,749.52	143	(80,000.00)	143
Generation	902382670 Interconnnection Study	19,577.48	143	(90,000.00)	143
Generation	902383242 Interconnnection Study	3,583.61	143	(3,483.09)	143
Generation	902386983 Interconnnection Study	5,299.33	143	(5,096.29)	143
Generation	902386984 Interconnnection Study	6,693.38	143	(6,441.47)	143
Generation	902386985 Interconnnection Study	6,553.78	143	(6,302.51)	143
Generation	902386986 Interconnnection Study	5,119.81	143	(4,927.48)	143
Generation	902387657 Interconnnection Study	8,778.18	143	(130,000.00)	143
Generation	902387715 Interconnnection Study	3,833.23	143	(3,682.60)	143
Generation	902387716 Interconnnection Study	4,666.62	143	(4,490.86)	143
Generation	902387717 Interconnnection Study	3,386.65	143	(3,300.72)	143

Generation	902387718 Interconnnection Study	6,564.24	143	(6,304.89)	143
Generation	902387735 Interconnnection Study	4,794.57	143	(4,614.13)	143
Generation	902387736 Interconnnection Study	5,625.91	143	(5,400.11)	143
Generation	902387737 Interconnnection Study	6,251.46	143	(6,008.63)	143
Generation	902387738 Interconnnection Study	3,079.81	143	(2,970.94)	143
Generation	902387799 Interconnnection Study	5,808.93	143	(5,583.68)	143
Generation	902387800 Interconnnection Study	5,647.21	143	(5,423.74)	143
Generation	902387801 Interconnnection Study	6,339.85	143	(6,098.04)	143
Generation	902387802 Interconnnection Study	117.51	143	-	143
Generation	902387879 Interconnnection Study	3,687.55	143	(3,553.18)	143
Generation	902387880 Interconnnection Study	4,578.10	143	(4,400.11)	143
Generation	902387939 Interconnnection Study	3,310.02	143	(3,187.64)	143
Generation	902387940 Interconnnection Study	5,044.19	143	(4,848.62)	143
Generation	902387941 Interconnnection Study	3,817.83	143	(3,664.74)	143
Generation	902388039 Interconnnection Study	2,972.49	143	(2,869.33)	143
Generation	902388370 Interconnnection Study	2,030.17	143	(1,963.03)	143
Generation	902388371 Interconnnection Study	2,840.69	143	(2,735.60)	143
Generation	902388372 Interconnnection Study	4,050.31	143	(3,891.99)	143
Generation	902388513 Interconnnection Study	7,538.47	143	(7,246.66)	143
Generation	902388981 Interconnnection Study	32,403.24	143	(70,000.00)	143
Generation	902388982 Interconnnection Study	22,472.34	143	(70,000.00)	143
Generation	902391215 Interconnnection Study		143	-	143
Generation	902391216 Interconnnection Study	18,578.33	143	(70,000.00)	143
Generation	902391217 Interconnnection Study	18,582.95	143	(70,000.00)	143
Generation	902391574 Interconnnection Study	27,367.98	143	(70,000.00)	143
Generation	902391575 Interconnnection Study	22,745.00	143	(70,000.00)	143
Generation	902391819 Interconnnection Study		143	-	143
Generation	902392000 Interconnnection Study	18,721.50	143	(53,000.00)	143
Generation	902392001 Interconnnection Study	18,812.43	143	(52,000.00)	143
Generation	902392002 Interconnnection Study	3,996.88	143	(10,000.00)	143
Generation	902392004 Interconnnection Study	20,240.21	143	(125,000.00)	143
Generation	902392017 Interconnnection Study	20,686.58	143	(52,000.00)	143
Generation	902392018 Interconnnection Study	20,102.06	143	(53,000.00)	143
Generation	902392134 Interconnnection Study	1,230.15	143	(10,000.00)	143
Generation	902392159 Interconnnection Study	5,417.84	143	(52,000.00)	143
Generation	902392214 Interconnnection Study	19,090.49	143	(130,000.00)	143
Generation	902392283 Interconnnection Study	21,358.93	143	(60,000.00)	143
Generation	902392284 Interconnnection Study	4,535.12	143	(80,000.00)	143
Generation	902392285 Interconnnection Study	19,017.87	143	(80,000.00)	143
Generation	902392287 Interconnnection Study	4,155.43	143	(80,000.00)	143
Generation	902392289 Interconnnection Study	5,302.00	143	(80,000.00)	143
Generation	902392290 Interconnnection Study	553.95	143	(56,000.00)	143
Generation	902392292 Interconnnection Study	1,795.36	143	(56,000.00)	143
Generation	902392293 Interconnnection Study	1,229.31	143	(56,000.00)	143
Generation	902392295 Interconnnection Study	1,335.24	143	(56,000.00)	143
Generation	902392296 Interconnnection Study	2,974.82	143	(20,000.00)	143
Generation	902392343 Interconnnection Study	23,944.75	143	(60,000.00)	143
Generation	902392468 Interconnnection Study	20,021.09	143	(200,000.00)	143
Generation	902392469 Interconnnection Study	28,701.00	143	(130,000.00)	143
Generation	902392470 Interconnnection Study	20,699.60	143	(130,000.00)	143
Generation	902392471 Interconnnection Study	20,994.50	143	(70,000.00)	143
Generation	902392472 Interconnnection Study	29,731.74	143	(130,000.00)	143
Generation	902392473 Interconnnection Study	1,995.93	143	(56,000.00)	143
Generation	902392474 Interconnnection Study	531.11	143	(56,000.00)	143
Generation	902392475 Interconnnection Study	756.03	143	(56,000.00)	143
Generation	902392476 Interconnnection Study	18,671.93	143	(65,000.00)	143
Generation	902392477 Interconnnection Study	17,807.34	143	(69,000.00)	143
Generation	902392478 Interconnnection Study	23,871.96	143	(69,000.00)	143

Generation	902392481 Interconnnection Study	24,610.55	143	(104,000.00)	143
Generation	902392482 Interconnnection Study	18,848.31	143	(63,000.00)	143
Generation	902392483 Interconnnection Study	20,856.73	143	(76,000.00)	143
Generation	902392676 Interconnnection Study	21,311.20	143	(145,000.00)	143
Generation	902392677 Interconnnection Study	20,755.71	143	(145,000.00)	143
Generation	902400189 Interconnnection Study	15,695.61	143	(60,000.00)	143
Generation	902400191 Interconnnection Study	19,116.66	143	(60,000.00)	143
Generation	902400235 Interconnnection Study	18,769.45	143	(60,000.00)	143
Generation	902400236 Interconnnection Study	18,037.49	143	(60,000.00)	143
Generation	902400389 Interconnnection Study	2,413.87	143	(53,000.00)	143
Generation	902400390 Interconnnection Study	21,233.85	143	(53,000.00)	143
Generation	902400391 Interconnnection Study	22,741.79	143	(60,000.00)	143
Generation	902400446 Interconnnection Study	19,913.98	143	(95,000.00)	143
Generation	902400450 Interconnnection Study	18,924.69	143	(70,000.00)	143
Generation	902400451 Interconnnection Study	14,822.48	143	(90,000.00)	143
Generation	902400452 Interconnnection Study	21,186.05	143	(80,000.00)	143
Generation	902400455 Interconnnection Study	14,962.53	143	(70,000.00)	143
Generation	902400853 Interconnnection Study	15,870.61	143	(60,000.00)	143
Generation	902400882 Interconnnection Study	20,378.27	143	(100,000.00)	143
Generation	902401093 Interconnnection Study	2,747.99	143	(53,000.00)	143
Generation	902401168 Interconnnection Study	5,876.77	143	-	143
Generation	902401353 Interconnnection Study	5,546.00	143	(5,315.31)	143
Generation	902403761 Interconnnection Study	9,526.77	143	-	143
Generation	902403810 Interconnnection Study	2,135.36	143	(2,059.67)	143
Generation	902404284 Interconnnection Study	25,245.00	143	(150,000.00)	143
Generation	902410968 Interconnnection Study	4,558.11	143	(4,399.40)	143
Generation	902410974 Interconnnection Study	19,795.21	143	-	143
Generation	902410975 Interconnnection Study	4,005.56	143	-	143
Generation	902411132 Interconnnection Study	24,231.10	143	-	143
Generation	902411225 Interconnnection Study	24,282.81	143	-	143
Generation	902411236 Interconnnection Study	24,928.37	143	-	143
Generation	902411237 Interconnnection Study	24,633.44	143	-	143
Generation	902411238 Interconnnection Study	24,680.61	143	-	143
Generation	902411245 Interconnnection Study	25,148.15	143	-	143
Generation	902411247 Interconnnection Study	25,686.75	143	-	143
Generation	902411249 Interconnnection Study	19,318.71	143	-	143
Generation	902411250 Interconnnection Study	20,894.16	143	-	143
Generation	902411251 Interconnnection Study	20,008.23	143	-	143
Generation	902411252 Interconnnection Study	20,893.76	143	-	143
Generation	902411253 Interconnnection Study	20,779.42	143	-	143
Generation	902411259 Interconnnection Study	24,788.03	143	-	143
Generation	902411271 Interconnnection Study	24,356.57	143	-	143
Generation	902411272 Interconnnection Study	20,951.26	143	-	143
Generation	902411273 Interconnnection Study	25,591.76	143	-	143
Generation	902411275 Interconnnection Study	20,489.05	143	-	143
Generation	902411276 Interconnnection Study	26,063.12	143	-	143
Generation	902411359 Interconnnection Study	21,417.26	143	-	143
Generation	902411360 Interconnnection Study	20,481.98	143	-	143
Generation	902411361 Interconnnection Study	19,742.28	143	-	143
Generation	902411363 Interconnnection Study	20,270.13	143	-	143
Generation	902411364 Interconnnection Study	20,148.61	143	-	143
Generation	902411365 Interconnnection Study	19,827.36	143	-	143
Generation	902411366 Interconnnection Study	11,001.24	143	-	143
Generation	902411367 Interconnnection Study	10,889.34	143	-	143
Generation	902411932 Interconnnection Study	1,198.71	143	(10,000.00)	143
Generation	902411936 Interconnnection Study		143	(10,000.00)	143
Generation	902417120 Interconnnection Study	894.62	143	-	143
Generation	902422029 Interconnnection Study	1,572.99	143	(20,000.00)	143

Generation	902423099 Interconnnection Study	5,187.10	143	(4,963.81)	143
Generation	902424760 Interconnnection Study	8,292.78	143	-	143
Generation	902424761 Interconnnection Study	8,300.81	143	-	143
Generation	902425160 Interconnnection Study	2,061.61	143	(60,000.00)	143
Generation	902429704 Interconnnection Study	732.58	143	-	143
Generation	902433589 Interconnnection Study	12,003.19	143	-	143
Generation	902433590 Interconnnection Study	12,003.19	143	-	143
Generation	902433592 Interconnnection Study	12,003.19	143	-	143
Generation	902433804 Interconnnection Study	12,003.19	143	-	143
Generation	902433805 Interconnnection Study	12,003.19	143	-	143
Generation	902433806 Interconnnection Study	12,003.19	143	-	143
Generation	902433807 Interconnnection Study	12,003.19	143	-	143
Generation	902434444 Interconnnection Study	12,003.19	143	-	143
Generation	902434447 Interconnnection Study	12,003.19	143	-	143
Generation	902434449 Interconnnection Study	12,003.19	143	-	143
Generation	902434452 Interconnnection Study	12,003.19	143	-	143
Generation	902434457 Interconnnection Study	12,003.19	143	-	143
Generation	902434459 Interconnnection Study	12,003.19	143	-	143
Generation	902434460 Interconnnection Study	832.90	143	(798.01)	143
Generation	902434499 Interconnnection Study	12,003.19	143	-	143
Generation	902434500 Interconnnection Study	20,449.17	143	-	143
Generation	902434501 Interconnnection Study	12,003.19	143	-	143
Generation	902434502 Interconnnection Study	832.90	143	(798.01)	143
Generation	902434503 Interconnnection Study	12,003.19	143	-	143
Generation	902434504 Interconnnection Study	12,003.19	143	-	143
Generation	902434505 Interconnnection Study	12,003.19	143	-	143
Generation	902434506 Interconnnection Study	12,003.19	143	-	143
Generation	902434507 Interconnnection Study	6,197.33	143	-	143
Generation	902434508 Interconnnection Study	6,197.33	143	-	143
Generation	902440019 Interconnnection Study		143	(10,000.00)	143
Generation	902440151 Interconnnection Study	1,888.37	143	-	143
Generation	902440982 Interconnnection Study	2,406.32	143	-	143
Generation	902443748 Interconnnection Study	1,052.88	143	(1,012.01)	143
Generation	902444603 Interconnnection Study	15,756.63	143	(10,000.00)	143
Generation	902444732 Interconnnection Study	596.40	143	(576.92)	143
Generation	902445314 Interconnnection Study	1,768.48	143	(1,685.60)	143
Generation	902447169 Interconnnection Study	1,445.48	143	(2,500.00)	143
Generation	902454929 Interconnnection Study	362.00	143	-	143
Generation	902457272 Interconnnection Study	6,541.62	143	-	143
Generation	902457843 Interconnnection Study	6,660.32	143	-	143
Generation	902462962 Interconnnection Study	4,755.15	143	(4,404.71)	143
Generation	902468404 Interconnnection Study	362.00	143	(10,000.00)	143
Generation	902469280 Interconnnection Study	865.31	143	-	143
Generation	902498289 Interconnnection Study	2,378.14	143	(101,000.00)	143
Generation	902498860 Interconnnection Study	2,321.25	143	-	143
Generation	902498861 Interconnnection Study	2,321.25	143	-	143
Generation	902498862 Interconnnection Study	2,321.25	143	-	143
Generation	902498864 Interconnnection Study	64.82	143	(10,000.00)	143
Generation	902505385 Interconnnection Study	6,511.06	143	-	143
Generation	902506134 Interconnnection Study	1,321.90	143	-	143
Generation	902506135 Interconnnection Study	836.56	143	-	143
Generation	902514479 Interconnnection Study	1,316.35	143	(10,000.00)	143
Generation	902514534 Interconnnection Study	267.06	143	(10,000.00)	143
Generation	902519539 Interconnnection Study	394.71	143	(10,000.00)	143
Generation	902531964 Interconnnection Study	1,550.22	143	-	143
Generation	902550947 Interconnnection Study		143	(51,000.00)	143
Generation	902559735 Interconnnection Study	863.30	143	-	143
	TOTAL GENERATION	**$ 3,811,273.29**		**$ (5,438,392.20)**	

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

Column (b) may not include A and G expenses for the period.

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

Column (d) includes refunds that were paid to the Interconnection customer in 2018 resulting from payment 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.

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Income Tax-Related Deferred Charges	3,230,636,303	771,938,280	Various	317,460,339	3,685,114,244
2	FASB 109 gross-up of taxes of flow-through					
3	temporary differences which reverse over time under					
4	various regulatory decisions like D.59926,					
5	D.15-011-021, D.14-12-082 and D.14-11-040. The					
6	amortization period depends on the types of flow-					
7	through temporary differences and there are num-					
8	erous.					
9						
10	Unamortized Cost - Palo Verde Commercial	280,071		406	9,798	270,273
11	Operating Date Adjustment					
12	To recover costs incurred between FERC and					
13	CPUC commercial operating date. (Amortization					
14	Period: 03/1988-07/2046) D.01-01-061					
15						
16	Palo Verde Units 2 & 3	1,126,174		Various	39,400	1,086,774
17	To recover deferred common facilities charges.					
18	(Amortization Period: 09/1986-07/2046) D.01-01-061.					
19						
20	Catastrophic Event Memorandum Account	117,417,040	60,441,037	407	33,413,191	144,444,886
21	To record costs incurred by SCE associated					
22	with a catastrophic event for restoring utility					
23	service to customers; repairing, replacing, or					
24	restoring damaged utility facilities; and complying					
25	with governmental agency orders. (CPUC: E-4791					
26	and E-3238 and Gov. State of Emergency Letters)					
27						
28	Environmental Clean-up Costs	95,756,377	1,533,984	253	5,297,706	91,992,655
29	To recover ratepayer's portion of environmental					
30	costs (D.94-05-020).					
31						
32	Hazardous Waste Balancing Account	2,743,667	3,991,687	254	4,757,651	1,977,703
33	To recover collaborative hazardous waste costs					
34	associated with cleaning up certain properties con-					
35	taminated with hazardous substances between the					
36	Company's ratepayers and shareholders					
37	(D.94-05-020).					
38						
39	Environmental Remediation	48,303,226	84,060	253	6,244,439	42,142,847
40	To recover 90% of estimated future environmental					
41	remediation/cleanup costs under a collaborative					
42	agreement (e.g. SCE and other third parties)					
43	D.94-05-020.					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unamortized Nuclear Plant	76,921,991	2,731,038	108	7,065,785	72,587,244
2	To reflect Palo Verde Nuclear Plant as a					
3	regulatory asset, D01-01-061.					
4	(Amortization Period: 03/1988-07/2046)					
5						
6	Nuclear Asset Retirement Obligation (ARO)	790,824	57,626,085	Various	58,232,560	184,349
7	To establish a regulatory asset for decommission-					
8	ing costs collected in rates for Nuclear and coal					
9	ARO property per FAS 143. (Amortization					
10	Period: 12/2003-12/2025)					
11						
12	Regulatory Asset Pension - SFAS 158	148,413,762	28,684,714	228	13,592,311	163,506,165
13	To reflect regulatory asset resulting from the					
14	adoption of SFAS 158 Employers' Accounting					
15	for Defined Benefit Pension & Other Postretirement					
16	Plans (D.06-05-016).					
17						
18	Leases for Power Contracts	1,002,221,353	1,835,179	Various	204,880,130	799,176,402
19	To record regulatory asset associated with power					
20	contracts that are subject to lease accounting					
21	rules under the guidance of EITF No. 01-8 and					
22	SFAS 13.(Amortization Period: 12/2006- 4/2026)					
23						
24	Misc. Balancing Account Activity	9,712,233	308,696,000	407	314,656,202	3,752,031
25	To capture various accrued purchased power					
26	agreements and other miscellaneous regulatory					
27	assets.					
28						
29	Fire Hazard Prevention Memorandum Account	530,848	30,640,070			31,170,918
30	To record the increase in costs incurred related to					
31	fire hazard prevention in compliance with Commis-					
32	sion Decision phase 1 D.09-08-029, phase 2 D.12-					
33	01-032, R. 15-05-006.					
34						
35	Renewable Portfolio Standard Costs Memorandum	1,226,947	14,096	253	1,241,043	
36	Account					
37	To record the (1) costs of studies of inter-					
38	connection facilities and network transmission up-					
39	grades necessary to interconnect RPS generation					
40	resources contracted in the 2003 and 2005 RPS					
41	solicitations and additional resources to be					
42	contracted in the future in accordance with					
43	ordering Paragraph No.1 of Resolution E-3969; (2)					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	costs of studies associated with the Tehachapi					
2	Wind Resource Area, in accordance with Ordering					
3	Paragraph No. 2 of Resolution E-3969; and (3)					
4	payments allocated to SCE for contractor(s) hired					
5	by Executive Director of the Commission to provide					
6	technical and other support to Commission Staff in					
7	the advancement of RPS goals, pursuant to Ordering					
8	Paragraph 8 of D.06-10-050 and D.14-05-002.					
9						
10	FAS 87 Pen Reg Asset	122,641,766		228	15,203,912	107,437,854
11	To record the cumulative difference between pension					
12	expense calculated for ratemaking purposes and the					
13	amount calculated for accounting purposes since					
14	implementation of SFAS 87 in 1987 (D.06-05-016).					
15						
16	Incurred But Not Reported Medical Claims	10,578,050		232	1,811,764	8,766,286
17	To record a regulatory asset for					
18	estimated costs of medical services rendered for					
19	which claims have not been filed or invoiced					
20	(Incurred But Not Reported) D.09-03-025.					
21						
22	Public Purpose Programs Adjustment Mechanism	20,507,976	360,367,662	Various	380,875,638	
23	To record Public Goods Charge Revenue, PGC					
24	expenses authorized in P.U. Code Section 399.8, and					
25	other CPUC Public Purpose Program revenues and					
26	expenses (D.11-12-038). Programs include: ESAP,					
27	CARE, EPIC, OBF, PEEBA, LCRPBA, and NSHF.					
28						
29	Agricultural Account Aggregation Study Memorandum	76,077	1,530			77,607
30	Account					
31	To record the costs, not to exceed $100,000,					
32	associated with a study that will examine the					
33	costs and benefits of agricultural customer					
34	account aggregation. Pursuant to Decision					
35	D.13-03-031, the costs of the study shall					
36	be recovered from Agricultural and Pumping					
37	customers through the distribution sub-account					
38	of the Base Revenue Requirement Balancing					
39	Account (BRRBA).					
40						
41	SONGS Technical Assistance Memorandum Account	3,256	3,335	254	6,591	
42	To record Commission-approved invoices for					
43	consultant costs incurred by the Commission and					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	paid by SCE in Connection with SONGS investigation.					
2	Pursuant to D.13-06-013, the Commission Energy					
3	Commission Energy Division Director is authorized					
4	to retain one or more consultants to provide tech-					
5	nical assistance to Commission staff and assigned					
6	Administrative Law Judges on the complex technical					
7	issues involved with I.12-10-013.					
8						
9	Energy Data Request Program Memorandum Account	481,307	9,676	407	83	490,900
10	To record SCE's incremental operation and					
11	maintenance (O&M) expenses and capital-related					
12	revenue requirements associated with the provision					
13	of access to energy usage and usage-related data					
14	to local government entities, researchers, and					
15	state and federal agencies, pursuant to Ordering					
16	Paragraph 13 of D.14-05-016.					
17						
18	Mobilehome park Master Meter Balancing Account		16,578,902	254	16,578,902	
19	To record actual incremental incurred costs of					
20	implementing the voluntary program to convert the					
21	electric master-meter/submeter service to direct					
22	service at Mobilehome Parks (MHP) and					
23	manufactured housing communities, pursuant to					
24	(D.) 14-03-021.					
25						
26	Litigation Costs Tracking Account	2,798,640	2,042,943	254	2,798,640	2,042,943
27	In accordance with Resolution E-3894, SCE shall					
28	maintain a Litigation Costs Tracking Account within					
29	the ESMA to track: 1) litigation costs that are					
30	“set-aside” in the FERC investigation settlement					
31	agreements; and 2) actual litigation costs incurred					
32	by SCE. Amounts recorded in the Litigation Costs					
33	Tracking Account shall be subject to audit in SCE's					
34	ERRA proceedings.					
35						
36	Net Energy Metering (NEM) Online Application	1,053,905	103,329	Various	38,702	1,118,532
37	System Memorandum Account					
38	To track the costs SCE incurs to establish an					
39	online application system for processing					
40	applications for interconnection under SCE’s					
41	NEM tariffs, pursuant to Decision D.14-11-001					
42	and D.16-01-044.					
43						
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Residential Energy Disconnections Memorandum	26,904	541			27,445
2	Accounts					
3	To record costs associated with implementation					
4	of the new practices and any uncollectibles					
5	exceeding authorized (D.12-03-054).					
6						
7	Green Tariff Shared Renewables Admin Cost	500,514	68,664	Various	375	568,803
8	Memorandum Account					
9	To record the difference between revenues collected					
10	through GTSR adminstrative charge and initial					
11	and on-going incremental administrative costs					
12	(D.15-01-051).					
13						
14	Green Tariff Marketing, Education & Outreach	381,188	8,433	Various	43,880	345,741
15	Memorandum Account					
16	To record the difference between revenues					
17	collected through Green Tariff ME&O costs and					
18	initial and on-going incremental ME&O costs					
19	(D.15-01-051).					
20						
21	Edison SmartConnect® Opt-Out Balancing Account	11,350,190	1,578,651			12,928,841
22	To record the difference between the revenues					
23	collected from customers that opt-out of a wireless					
24	smart meter and the costs incurred resulting from					
25	this opt-out election, excluding related exit-fee					
26	costs (D.14-12-078).					
27						
28	Greenhouse Gas (GHG) Administrative Costs Memorandn		268,411	Various	268,411	
29	To record the initial and on-going administrative					
30	costs incurred in order to implement the					
31	Commission-adopted GHG revenue allocation					
32	methodology, pursuant to D.12-12-033.					
33						
34	Residential Rate Implementation Memorandum Account	17,706,619	14,922,280	Various	442,865	32,186,034
35	To record SCE's incremental operation and					
36	maintenance (O&M) costs and capital revenue					
37	requirement associated with complying with the					
38	direction of the Commission in Decision D.15-07-001					
39	and Resolution E-4761 on Residential Rate Reform					
40	and Transition to Time-of-Use (TOU) Rates.					
41						
42	Reliability Service Balancing Account	5,531,547	988,712	Various	5,376,960	1,143,299
43	To track the RS revenues and RS costs to					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

OTHER REGULATORY ASSETS (Account 182.3)

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3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	ensure that SCE neither over-collects nor					
2	under-collects RS costs assessed (D.06-05-016).					
3						
4	Mobilehome Park Master Meter Regulatory Asset	45,469,431	28,248,089	Various	22,801,414	50,916,106
5	To record Mobile Home Park Master Meter					
6	property, plant & equipment, and other as					
7	a regulatory asset (D.14-03-021).					
8						
9	GHG Revenue Balancing Account		533,576,256	Various	511,659,479	21,916,777
10	To record the difference between the amount of GHG					
11	revenue actually returned to customers via rates					
12	and bill credits, and the actual amount of GHG					
13	revenue SCE receives through consigning allow-					
14	ances to the cap and trade auction D.12-12-033.					
15						
16	Building Benchmarking Data Memo Account	195,291	524,897	407	156,619	563,569
17	To track SCE's incremental costs associated with					
18	maintaining energy usage data and providing this					
19	data to building owners and their agents as					
20	required by Assembly Bill 802. BBDMA shall be					
21	determined in future ERRA applications.					
22						
23	BioRAM Memorandum Account	9,705,108	10,703,652			20,408,760
24	To track the procurement costs incurred as the					
25	result of the requirements of Resolution E-4770					
26	that ordered SCE to solicit capacity generated from					
27	biofuel supplied from dead and dying forest mat-					
28	erial in high hazard zones to address an Emergency					
29	Proclamation using the Renewable Action Mechanism					
30	(RAM) procurement process (Resolution E-4805).					
31						
32	Pole Loading and Deteriorated Pole Balancing Accout	2,616,518	242,422,089	Various	82,146,333	162,892,274
33	To record the difference between recorded capital-					
34	related revenue, operating expenses, and the					
35	authorized revenue requirement authorized by					
36	D.15-11-021.					
37						
38	Mitsubishi Net Litigation Account	3,988,316	49,589	Various	4,037,905	
39	To record the difference between litigation costs					
40	incurred to secure recoveries from Mitsubishi as of					
41	January 31, 2012, and proceeds received from					
42	Mitsubishi pursuant to D.14-11-040.					
43						
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
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Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	Energy Resource Recovery Account	464,403,442	671,454,639	Various	320,425,768	815,432,313
3	To record SCE's ERRA Revenue, Utility Retained					
4	Generation fuel costs, and purchased power related					
5	expenses D.02-10-062.					
6						
7	Gas Cost Adjustment Billing Balancing Account	176,968	239,243	Various	190,884	225,327
8	Balance composed of Gas Cost Adjustment Clause					
9	which recovers/refunds gas costs on Catalina Island					
10	D.82-04-010.					
11						
12	Local Capacity Requirements Products Balancing		13,461,016	Various	13,461,016	
13	Account					
14	To record local capacity requirements (LCR) request					
15	for offers (RFO) resource costs pursuant to					
16	D.15-11-041 and D.16.05.050.					
17						
18	Charge Ready Program Balancing Account		2,912,907	Various	2,912,907	
19	To record the actual incremental operations and					
20	maintenance (O&M) expense and capital related					
21	revenue requirements associated with Phase 1 of					
22	the Charge Ready Program (CRP) and Market Education					
23	Program pursuant to D.16-01-023.					
24						
25	Post Employment Benefit Accrual	49,241,493		228	28,612,388	20,629,105
26	To reflect a regulatory asset for future recovery					
27	of post employment benefits per SFAS 112.					
28						
29	Wheeler North Reef Expansion Project Memo Account	619,332	1,909,285	Various	496,578	2,032,039
30	To track SCE's costs associated with the WNR Expan-					
31	sion Project pursuant to the Administrative Law					
32	Judge's Ruling Granting SCE's Motion to Establish					
33	a Memorandum Account Subject to Conditions Set					
34	Forth Herein and Commission Approval of Final					
35	Decision in this Proceeding (Application					
36	(A.) 16-12-002) dated May 1, 2017.					
37						
38	BioMass Memorandum Account	10,250,942	20,791,826	Various	432,925	30,609,843
39	To track the procurement costs incurred as the					
40	result of the requirements of Commission Resolution					
41	E-4805 that ordered SCE to solicit capacity gener-					
42	ated from biofuel supplied from dead and dying					
43	forest material from Fuel High Hazard Zones (HHZ)					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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1	pursuant to Senate Bill (SB) 859 and Resolution					
2	E-4770 that also ordered SCE to solicit capacity					
3	generated from biofuel supplied from dead and					
4	dying forest material from HHZs.					
5						
6	NEM-A Billing Automation Costs Memo Account	22,924	22,142	Various	23,488	21,578
7	To track the costs that SCE incurs to automate Net					
8	Energy Metering Automation (NEM-A) in its billing					
9	system and produce automated bills for customers					
10	electing to participate in NEM-A over the course of					
11	one year, pursuant to Resolution E-4881.					
12						
13	Enhanced Community Renewables Marketing, Education	14,208	11,308			25,516
14	& Outreach Memo Account					
15	To record the difference between the revenues					
16	collected through the ECR ME&O Charge and initial					
17	and on-going incremental ME&O costs incurred in					
18	order to implement the Commission-adopted ECR					
19	program, pursuant to D.15-01-051.					
20						
21	Nuclear Decommissioning Adjustment Mechanism	118,007	223,978	254	341,985	
22	To record NDAM revenue, authorized and recorded					
23	costs related to the decommissioning of San Onofre					
24	Nuclear Generating Station and Palo Verde Nuclear					
25	Generating Station, pursuant to D.04-07-022.					
26						
27	Regulatory Asset Fire Insurance		62,424,599	407	31,260,337	31,164,262
28	To record regulatory asset for non-incremental					
29	wildfire insurance costs.					
30						
31	Emergency Customer Protection Memo Account		59,634			59,634
32	To record costs associated with customer pro-					
33	tections pursuant to Resolution M-4833.					
34						
35	Integrated Distributed Energy Resources Adm Costs		228,992			228,992
36	Memo Account					
37	To record solicited-related incremental adminis-					
38	trative costs associated with the Utility					
39	Regulatory Incentive Pilot as adopted in					
40	Decision 16-12-036.					
41						
42	Power Charge Indifference Adjustment Memo Account		23,781			23,781
43	To record and track the costs associated with the					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OTHER REGULATORY ASSETS (Account 182.3)

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1	educaiton and outreach effort for California					
2	Alternate Rate for Energy (CARE) and Medical Base-					
3	line (MB) program customers impacted by the					
4	elimination of the exemption from paying the PCIA					
5	per Decision 18-07-009.					
6						
7	Wildfire Expense Memo Account		128,416,817			128,416,817
8	To track all amounts paid as a result of wildfire,					
9	and that were not previously authorized in the					
10	SCE's General Rate Case (GRC), per Decision					
11	D.18.11-051.					
12						
13	Transportation Electrification Portfolio Balancing		2,085,658	254	2,085,658	
14	Account					
15	To record the actual Operations and Maintenance					
16	(O&M) expenses and capital-related revenue require-					
17	ments (i.e. depreciation, return on rate base, and					
18	applicable taxes) associated with the approved					
19	Transportation Electrification Priority Review					
20	Projects (PRPs). Separate subaccounts are estab-					
21	lished in the TEPBA to ensure that SCE will only					
22	recover the revenue requirements assoicated with up					
23	to the total capped level of authorized funding for					
24	each of the individual PRPs and SCE's share of					
25	evaluation costs, pursuant to D.18-01-024.					
26						
27	Distribution Resources Plan Demonstration Balancing		12,207			12,207
28	Account					
29	To record revenue requirements associated in					
30	Operations & Maintenance (O&M) expenses and capital					
31	expenditures for SCE's Demonstration Project C as					
32	authorized in D.17-02-007.					
33						
34	Demand Response Program Balancing Account		402,332	254	402,332	
35	To support SCE's recovery of expenses related to					
36	its demand response programs recorded in the					
37	Demand Response Program Balancing Account					
38	(DRPBA). The Resolution granted SCE its proposed					
39	budget for additional improvements in direct parti-					
40	cipation demand response implementation including					
41	development of Click-Through, activities to help i					
42	increase enrollments in third party demand reponse					
43	programs, and costs for increasing customer					
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	registrations in the CAISO wholesale market per					
2	E3774 D.18-05-041.					
3						
4	CARE Balancing Account		4,454,578	254	4,454,578	
5	To reflect in rates, through application of the					
6	Public Purpose Program Charge the costs associated					
7	with the CARE Program as authorized in various					
8	CPUC Decisions (D. 89-07-062, 89-09-044,					
9	92-04-024, 92-06-060, 94-12-049 and 95-10-047).					
10						
11	Green Tariff Shared Renewables Balancing Account		11,398	254	11,398	
12	To record the difference between the actual revenue					
13	requirements, based on recorded GTSR commodity-					
14	related costs, and the revenues collected from					
15	individual customers electing to participate in the					
16	GTSR Program through charges set to collect					
17	these costs (D.15-01-051).					
18						
19	Aliso Canyon Energy Storage Balancing Account		27,435,680	254	27,435,680	
20	To record the Tesla and General Electric projects'					
21	actual revenue requirements. The ACESBA will					
22	separately account for and record the revenue					
23	requirements for the Tesla projects and the General					
24	Electric projects per decision D.18-06-027.					
25						
26	Transmission Revenue Balancing Account		10,303,510	254	802,398	9,501,112
27	To record transmission revenue credits, congestion					
28	revenue, wheeling revenue, sale of an FTR revenue,					
29	and ancillary service expense to the TRBAA.					
30	Authorized by ER18-154-000					
31						
32	Purchase Power Settlements		206,375,000			206,375,000
33	Termination of purchase power contracts.					
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	5,516,540,735	3,633,944,401		2,444,489,348	6,705,995,788

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Prepaid Software License	2,092,354	4,479,932	Various	1,369,409	5,202,877
2	(Amort. Period:11/2014-3/2021)					
3	OWIP - ECS Def Debit	5,208,661	15,794,932	Various	11,703,608	9,299,985
4						
5	Plant Claims Pending	9,818,063	224,394	Various	1,989,946	8,052,511
6						
7	SLU Def Proj Cost	35,698				35,698
8						
9	SONGS Nuc Fuel Stor./Other Cost	13,286,363	4,244,923	Various	1,029,764	16,501,522
10	CARB Admin Fees			Various		
11	OBF Loan Payment		1,950,414	Various	1,950,414	
12	Misc. Deferred Debits	889	2,539,310	Various	1,351,346	1,188,853
13						
14						
15						
16						
17						
18						
19						
20						
21						
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42						
43						
44						
45						
46						
47	Misc. Work in Progress	63,160,987				61,157,503
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	93,603,015				101,438,949

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	See Attached Schedule	1,722,386,625	2,266,757,712
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	1,722,386,625	2,266,757,712
9	Gas		
10	See Attached Schedule	117,837	140,873
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	117,837	140,873
17	Other Income	-10,934,985	3,426,533
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,711,569,477	2,270,325,118

Notes

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
190	Amort of Debt Issuance Cost	649,241	672,292
190	Executive Incentive Comp	3,146,087	2,228,654
190	Bond Discount Amort	771,695	801,941
190	Executive Incentive Plan	1,536,403	1,143,688
190	Ins - Inj/Damages Prov	29,451,918	28,251,649
190	Accrued Vacation	11,617,959	13,408,092
190	PBOP 401H Amortization	34,717,749	(0)
190	EMS	1,247,125	-
190	Amortization of Debt Expense	955,103	1,141,054
190	Wildfire Reserve	-	746,882,284
190	Decommissioning	421,953,973	339,698,463
190	Balancing Accounts	(9,045,539)	(11,619,374)
190	Pension & PBOP	9,082,254	40,171,080
190	Property/Non-ISO	6,708,625	6,547,986
190	Regulatory Assets/Liab	9,519,058	36,181,620
190	Temp - Other/Non-ISO	1,027,410,562	868,848,855
190	Net Operating Losses DTA	172,664,412	192,399,428
	Total Electric	1,722,386,625	2,266,757,712

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS:			
190	Balancing Accounts	-	-

190	Temp - Other/Non-ISO	(910)	140,873
190	Net Operating Losses DTA	118,747	-
	Total Gas	117,837	140,873

Schedule Page: 234 Line No.: 17 Column: a

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER INCOME:			
190	Balancing Accounts	2,738,774	0
190	Temp - Other/Non-ISO	1,561,144	2,269,027
190	Net Operating Losses DTA	(15,234,903)	-
190	EMS	0	1,157,506
	Total Other	(10,934,985)	3,426,533

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	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			
9				
10	$25 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	Preferred Stock - with Mandatory Redemption			
17	Requirements			
18	$100 Cumulative Preferred:	12,000,000	100.00	100.00
19				
20				
21	Preference Stock			
22	No Par Value	50,000,000		
23				
24	Non-Voting and Cumulative			
25				
26	6.250% SERIES E		1,000.00	1,000.00
27	5.100% SERIES G		2,500.00	2,500.00
28	5.750% SERIES H		2,500.00	2,500.00
29	5.375% SERIES J		2,500.00	2,500.00
30	5.450% SERIES K		2,500.00	2,500.00
31	5.000% SERIES L		2,500.00	2,500.00
32	TOTAL_PRE	86,000,000		
33				
34				
35				
36				
37				
38				
39				
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41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
Shares (e)	Amount (f)	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
						21
						22
						23
						24
						25
350,000	350,000,000					26
160,004	400,010,000					27
110,004	275,010,000					28
130,004	325,010,000					29
120,004	300,010,000					30
190,004	475,010,000					31
5,860,218	2,245,054,950					32
						33
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						40
						41
						42

Schedule Page: 250 Line No.: 21 Column: a

SCE has authorization from CPUC to issue up to $1.055 billion additional preferred equity.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Accounts 208 and 209	
2	None	
3		
4	Account 210	
5	Gain on Reacquired Preferred Stock (2008)	1,746,500
6		
7	Miscellaneous Paid-in Capital (Account 211)	
8		
9	Respondent issued 778,150 shares of Common Stock in the form of	
10	a 4% stock dividend to the holders of Original Preferred and	
11	Common Stock on January 5, 1961.	
12		
13	778,150 X 32.875 $25,581,681.25 (Market Value)	
14	778,150 X 12.500 9,726,875.00	15,854,806
15		
16	Respondent recorded this amount ($51,497) as a result of merging	
17	with California Electric Power Co., which in turn had recorded it	
18	in connection with the acquisition of a subsidiary company in 1948.	51,497
19		
20	Respondent issued 7,220,000 shares of Common Stock and 296,769	
21	shares of 4.78% Cumulative Preferred Stock to the respective	
22	holders on December 31, 1963, of California Electric Power Co.	
23	Common and $3 Cumulative Preferred Stock.	
24		
25	Common Stock:	
26	Acquired Book Value - $37,570,757.06	
27	Account 201 (7,220,000 X 4 -1/6) = 30,083,333.33	7,487,424
28		
29		
30	4.78% Cumulative Preferred Stock:	
31	Acquired Book Value - $4,946,150.00	
32	Account 201 (296,769 X $25.00) = 7,419,225.00	-2,473,075
33		
34		
35		
36	Return of money deposited in Trust Fund for redemption of	
37	Cumulative Preferred Stock - 4.88% Series.	10,445
38		
39		
40	TOTAL	732,727,600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	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		
36	Stock Options Exercised (1998)	600,289
37		
38	Edison International Capital Contribution (1998)	153,000,000
39		
40	TOTAL	732,727,600

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 Awads (2008)	4,136,174
27		
28	Stock Based Compensation (2009)	12,969,153
29		
30	Excess Tax Benefits Related to Stock Based Awards (2009)	6,670,516
31		
32	Stock Based Compensation (2010)	17,123,627
33		
34	Excess Tax Benefits Related to Stock Based Awards (2010)	3,558,644
35		
36	Stock Based Compensation (2011)	15,547,616
37		
38	Excess Tax Benefits Related to Stock Based Awards (2011)	10,630,927
39		
40	TOTAL	732,727,600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Miscellaneous Paid-in Capital (Account 211) Continued:	
2		
3	Stock Based Compensation (2012)	17,749,941
4		
5	Excess Tax Benefits Related to Stock Based Awards (2012)	-12,656,585
6		
7	Stock Based Compensation (2013)	15,245,245
8		
9	Excess Tax Benefit Related to Stock Based Awards (2013)	1,668,969
10		
11	Stock Based Compensation (2014)	13,222,400
12		
13	Excess Tax Benefit Related to Stock Based Awards (2014)	19,591,400
14		
15	Stock Based Compensation (2015)	12,966,427
16		
17	Excess Tax Benefit Related to Stock Based Awards (2015)	22,668,074
18		
19	Stock-based Compensation (2016)	9,959,128
20		
21	Excess Tax Benefit Related to Stock Based Awards (2016)	-458,168
22		
23	Stock-based Compensation (2017)	10,912,673
24		
25	Stock-based Compensation (2018)	9,906,841
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	732,727,600

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		
11		
12	6.250% SERIES E	5,957,289
13	5.100% SERIES G	12,972,287
14	5.750% SERIES H	6,272,358
15	5.375% SERIES J	6,419,578
16	5.450% SERIES K	6,959,810
17	5.000% SERIES L	12,800,620
18		
19		
20		
21		
22	TOTAL	53,195,017

Schedule Page: 254 Line No.: 12 Column: a

Discount on Capital Stock (Account 213) at Year end is $583.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)		Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221			
2	First and Refunding Mortgage Bonds:			
3	Series 2004B	6.0	525,000,000	4,809,750
4				3,470,250 D
5	Series 2004G	5.75	350,000,000	3,062,500
6				154,000 D
7	Series 2005B	5.55	250,000,000	2,341,346
8				732,500 D
9	Series 2005E	5.35	350,000,000	3,062,500
10				168,000 D
11	Series 2006A	5.625	350,000,000	3,430,000
12				857,500 D
13	Series 2006E	5.55	400,000,000	4,000,000
14				2,176,000 D
15	Series 2008A	5.95	600,000,000	6,350,000
16				2,760,000 D
17	Series 2008B	5.50	400,000,000	2,272,000 D
18				3,250,000
19	Series 2009A	6.05	500,000,000	4,095,000 D
20				4,375,000
21	Series 2010A	5.50	500,000,000	6,015,000 D
22				5,350,000
23	Series 2010B	4.50	500,000,000	3,180,000 D
24				5,325,000
25	Series 2011A	3.875	500,000,000	2,885,000 D
26				4,285,000
27	Series 2011E	3.900	250,000,000	1,405,000 D
28				2,712,500
29	Series 2012A	4.050	400,000,000	4,728,000 D
30				4,300,190
31	Series 2013A	3.900	400,000,000	2,388,000 D
32				4,321,820
33	TOTAL		13,941,431,347	194,491,602

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)		Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221 Continued:			
2	First and Refunding Mortgage Bonds			
3				
4	Series 2013C	3.500	600,000,000	1,056,000 D
5				5,213,033
6	Series 2013D	4.650	800,000,000	5,504,000 D
7				8,347,631
8	Series 2015A	1.845	550,000,000	
9				4,452,468
10	Series 2015B	2.40	325,000,000	22,750 D
11				2,644,788
12	Series 2015C	3.60	425,000,000	1,632,000 D
13				4,677,785
14	Series 2017A	4.00	1,000,000,000	10,623,087
15				490,000 D
16				-21,849,000 P
17				
18	Series 2018A	2.90	450,000,000	1,906,478
19				189,000 D
20	Series 2018B	3.65	400,000,000	3,305,768
21				728,000 D
22	Series 2018C	4.13	1,300,000,000	13,389,459
23				11,850,500 D
24	Series 2018D	3.40	300,000,000	2,238,406
25				312,000 D
26	Series 2018E	3.70	300,000,000	2,227,941
27				21,208,000 D
28	SONGS_2006A	1.375	157,500,000	977,486
29				
30	SONGS_2006B	1.90	38,500,000	325,161
31				
32	SONGS 2006C&D	2.625	135,000,000	2,490,033
33	TOTAL		13,941,431,347	194,491,602

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	CLARK COUNTY 2010 1.875	75,000,000	873,795
3			
4	4CRNRS 2011 1.875	55,540,000	994,726
5			
6	Series PV 2000AB 5.00	144,400,000	1,300,000
7			
8	Account 221 Continued:		
9	First and Refunding Mortgage Bonds		
10			
11	Series 4CRNRS 05AB 1.875	203,460,000	2,271,452
12			
13	SONGS 2010A 4.50	100,000,000	2,000,000
14			
15	CPCFA SONGS 2011 Variable	30,000,000	350,000
16			
17	SUBTOTAL Account 221	13,664,400,000	190,014,603
18			
19	Account 222 (REACQUIRED BONDS)		
20			
21	CPCFA SONGS 2011 Variable	-30,000,000	-350,000
22			
23	SUBTOTAL- Account 222	-30,000,000	-350,000
24			
25	Account 224-Other Long-Term Debt:		
26	6.65% Notes 6.650	300,000,000	1,212,000
27			3,615,000 D
28	Ft. Irwin Loan 5.06	7,031,347	
29			
30	Capitalized Interest Related to Nuclear Fuel		
31	Rounding Adjustment		-1
32	SUBTOTAL- Account 224	307,031,347	4,826,999
33	TOTAL	13,941,431,347	194,491,602

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
01/14/04	01/15/34	01/14/04	01/15/34	525,000,000	31,500,000	3
						4
03/23/04	04/01/35	03/23/04	04/01/35	350,000,000	20,125,000	5
						6
01/19/05	01/15/36	01/19/05	01/15/36	250,000,000	13,875,000	7
						8
06/27/05	7/15/35	6/27/05	07/15/35	350,000,000	18,725,000	9
						10
01/31/06	02/01/36	01/31/06	02/01/36	350,000,000	19,687,500	11
						12
12/11/06	01/15/37	12/11/06	01/15/37	400,000,000	22,200,000	13
						14
01/22/08	02/01/38	01/22/08	02/01/38	600,000,000	35,700,000	15
						16
08/18/08	08/15/18	8/18/08	08/15/18		13,688,889	17
						18
03/20/09	03/15/39	03/20/09	03/15/39	500,000,000	30,250,000	19
						20
3/11/10	03/15/40	03/11/10	03/15/40	500,000,000	27,500,000	21
						22
08/30/10	09/01/40	08/30/10	09/01/40	500,000,000	22,500,000	23
						24
05/17/11	06/01/21	05/17/11	06/01/21	500,000,000	19,375,000	25
						26
11/22/11	12/01/41	11/22/11	12/01/41	250,000,000	9,750,000	27
						28
03/13/12	03/15/42	03/13/12	03/15/42	400,000,000	16,200,000	29
						30
03/07/13	03/15/43	03/07/13	03/15/43	400,000,000	15,600,000	31
						32
				13,108,390,453	549,367,056	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 Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
10/02/13	10/01/23	10/02/13	10/01/23	600,000,000	21,000,000	4
						5
10/02/13	10/01/43	10/02/13	10/01/43	800,000,000	37,200,000	6
						7
01/26/15	02/01/22	01/26/15	02/01/22	275,000,000	5,556,964	8
						9
01/26/15	02/01/22	01/26/15	02/01/22	325,000,000	7,800,000	10
						11
01/26/15	02/01/45	01/26/15	02/01/45	425,000,000	15,300,000	12
						13
03/24/17	04/01/47	03/24/17	04/01/47	1,000,000,000	40,000,000	14
						15
						16
						17
03/05/18	03/01/21	03/05/18	03/01/21	450,000,000	10,730,000	18
						19
03/05/18	03/01/28	03/05/18	03/01/28	400,000,000	12,004,444	20
						21
03/05/18	03/01/48	03/05/18	03/01/48	1,300,000,000	31,258,333	22
						23
06/04/18	06/01/23	06/04/18	06/01/23	300,000,000	5,865,000	24
						25
08/02/18	08/01/25	08/02/18	08/01/25	300,000,000	4,594,167	26
						27
04/05/13	04/01/28	04/05/13	04/01/28		547,422	28
						29
04/05/13	04/01/28	04/05/13	04/01/28	38,500,000	731,500	30
						31
04/12/06	11/01/33	04/12/06	11/01/33	135,000,000	3,543,750	32
				13,108,390,453	549,367,056	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 Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
04/01/15	06/01/31	04/01/15	06/01/31	75,000,000	1,406,250	2
						3
04/01/15	04/01/29	04/01/15	04/01/29	55,540,000	1,041,375	4
						5
03/01/04	06/01/35	03/01/04	06/01/35	144,400,000	7,220,000	6
						7
						8
						9
						10
04/01/15	04/01/29	04/01/15	04/01/29	203,460,000	3,814,875	11
						12
09/21/10	0901/29	09/21/10	09/01/29	100,000,000	4,500,000	13
						14
09/01/11	09/01/31	09/01/11	09/01/31			15
						16
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	12,801,900,000	530,790,469	17
						18
						19
						20
09/01/11	09/01/31	09/01/11	09/01/31			21
						22
						23
						24
						25
04/01/99	04/01/29	04/01/99	04/01/29	300,000,000	19,950,000	26
						27
09/01/03	09/01/53	09/01/03	09/01/53	6,490,453	330,272	28
						29
xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx	xxxxxxxxxx		-1,703,686	30
					1	31
				306,490,453	18,576,587	32
				13,108,390,453	549,367,056	33

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

NOTES TO PAGE 256-257A

(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, 2018 will be: $79M for 2019; $79M for 2020; $1,029M for 2021; $364M for 2022; and $900M for 2023.

(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 2018, respondent capitalized a portion of interest expense on long-term debt for the purpose of financing the company's nuclear fuel inventory. For 2018 the capitalized interest related to nuclear fuel totaled $1,703,686.

Reconciliation of Interest Expense on long-term debt:

Account 427	549,367,056
	549,367,056
	(0)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	-189,375,585
2		
3		
4	Taxable Income Not Reported on Books	
5		386,091,668
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		4,044,289,545
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		-151,370,078
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-4,237,507,967
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-147,872,417
28	Show Computation of Tax:	
29	Federal Tax @ 21%	-31,053,208
30		
31		
32	Alternative Minimum Tax	-19,181,569
33	Alternative Minimum Tax LT	-19,181,568
34	FIN 48 Adjustments	-1,570,312
35	Return To Provision Adjustment	-13,115,158
36	NOL Reclass	31,053,208
37		
38		
39		
40	Total Federal Income Tax Expense/(Benefit) Accrual	-53,048,607
41		
42		
43		
44		

Schedule Page: 261 Line No.: 1 Column: b

	YTD Total 2018
Book Income/(loss) - Pre Tax	(885,570,779)
CA State tax expense	(297,701,320)
Federal Tax Expense	(398,493,873)
Net income/(loss) per FERC Form 1 (pg. 117 - Col C, Line 78)	(189,375,585)

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

Taxable Income Not Recorded on Books	**YTD Total 2018**
M1 (Line 1)	
CIAC/ITCC	169,715,384
Decommissioning	133,774,182
Permanent - Others	82,602,102
	386,091,668

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

Deductions Recorded on Books Not Deducted for Return	**YTD Total 2018**
M1 (Line 2)	
Book Depreciation	1,910,531,673
Audit Rollforwards	3,486,760
Balancing Accounts	94,142,007
Pension and PBOPs	8,776,682
Federal Tax Expense	(398,493,873)
CA State tax expense	(297,701,320)
Regulatory Assets/Liab	(20,724,690)
Permanent - Others	22,486,952
Temporary - Others	52,785,355
SONGS Asset Impairment	-
Wildfire Reserve	2,669,000,000
	4,044,289,545

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

Income Recorded on Books Not Included in Return	**YTD Total 2018**
M1 (Line 3)	
AFUDC Equity/Debt	148,016,159
Permanent - Others	3,353,919
	151,370,078

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

Deductions on Return Not Charged Against Book Income	**YTD Total 2018**
M1 (Line 4)	

Tax Depreciation	1,423,784,596
Repairs Deduction	942,642,477
Removal Costs	713,082,682
Gain/(Loss) on Disposition	-
Capitalized Software labor	133,063,646
Mixed Service Cost	145,893,650
Decommissioning	140,541,977
Balancing Accounts	898,869,446
Temporary - Others	(130,730,631)
Permanent - Others	42,432,027
CCFT Lag - Electric Current Year	(72,464,947)
State and Local Tax	-
NOL - Fed	-
Regulatory Assets/Liab	393,044
	4,237,507,967

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL TAXES:					
2						
3	Federal Income Taxes	-170,658,413		-53,048,607	57,662,259	65,694,985
4	Tax Reserve - Regulatory	46,330,937				-71,889,280
5	Income Taxes	229,434,809				-103,526,690
6	Fed Ins Cont Act- Current	1,797,609		109,814,834	-109,824,827	-259,720
7	FICA/OASDI Emp Incntv	7,220,900		926,507		
8	FICA/HIT Emp Incntv	1,838,641		179,279		
9	Fed Unemp Tax Act-Current	1,993,970		741,309	-2,585,857	-1,145,387
10						
11	SUBTOTAL- FED TAXES :	117,958,453		58,613,322	-54,748,425	-111,126,092
12						
13	STATE TAXES :					
14						
15	CA Corp. Franchise Tax	-78,154,137		-28,178,436		22,078,193
16	Income Tax- Arizona	717,503			-970,222	
17	Income Tax- New Mexico	-500				
18	Income Tax- UT & CO					
19	Income Tax- DC	-6,519				
20	Accr Tax FIN48staST					-101,171,684
21	Ppd Inc Tax(Income					185,685,802
22						
23						
24	CA SUI Current	126,799		5,866,320	-5,907,256	-2,380
25	SUI TAX - NEVADA	87		1,647	-1,712	
26	ACCD SUI TAX - WASH D.C.			162	-261	-99
27	D.C. SUI TAX -EME	-99				99
28	SF Pyrl Exp Tx - SCE	-9,742		4,032	-48,139	
29	CADI Vol Plan Assess	246,109		1,781,251	-1,766,912	
30	Use Tax-California-Current	289,029		331,134	-540,730	
31	Accrued District/Local use CA	74,019		45,277	-109,967	
32	SALES TAX ACCRUED					
33	SALES TAX ACCRUED	10,542,462		57,795,236	-57,221,426	
34	Sales Tax Payable - CA	16,597		1,982	-1,934	
35	Sales Tax Payable - District					
36	Other Taxes Payable Contra					
37	Sales Tax Accrued/Contra					
38						
39	SUBTOTAL-STATE TAXES:	-66,158,392		37,648,605	-66,568,559	106,589,931
40						
41	TOTAL	51,800,061	-18,434,672	434,596,915	-454,919,129	-4,536,161

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	LOCAL TAXES:					
2						
3	Property Tax-Ariz Current			5,512,932	-8,320,859	2,807,927
4	Property Tax-Ariz Prepaid			2,807,927		-2,807,927
5	Property Tax-Calif Current			229,052,679	-324,013,425	94,960,746
6	Property Tax-Calif Prepaid		-17,993,889	99,027,087	348,734	-94,960,746
7	Property Tax-D.C. Current					
8	Property Tax-Nevada Current			341,804	-1,649,293	1,307,489
9	Property Tax-Nevada Prepaid		-440,783	1,592,559	32,698	-1,307,489
10	Property Tax-N Mex Current					
11	Property Tax-N Mex Prepaid					
12						
13	SUBTOTAL- LOCAL TAXES		-18,434,672	338,334,988	-333,602,145	
14						
15						
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22						
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26						
27						
28						
29						
30						
31						
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33						
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35						
36						
37						
38						
39						
40						
41	TOTAL	51,800,061	-18,434,672	434,596,915	-454,919,129	-4,536,161

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
-100,349,776		-47,671,179			-5,377,428	3
-25,558,343						4
125,908,119						5
1,527,896		109,634,389			180,445	6
8,147,407		965,694			-39,187	7
2,017,920		138,238			41,041	8
-995,965		740,442			867	9
						10
10,697,258		63,807,584			-5,194,262	11
						12
						13
						14
-84,254,380		-26,719,511			-1,458,925	15
-252,719						16
-500						17
						18
-6,519						19
-101,171,684						20
185,685,802						21
						22
						23
83,483		5,859,182			7,138	24
22					1,647	25
-198		162				26
						27
-53,849		4,052			-20	28
260,448		1,794,719			-13,468	29
79,433					331,134	30
9,329					45,277	31
						32
11,116,272					57,795,236	33
16,645					1,982	34
						35
						36
						37
						38
11,511,585		-19,061,396			56,710,001	39
						40
22,208,843	-13,701,828	362,505,870			72,091,045	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
		5,499,792			13,140	3
		2,796,197			11,730	4
		214,272,959			14,779,720	5
	-13,578,813	93,690,795			5,336,292	6
						7
		294,448			47,356	8
	-123,015	1,205,491			387,068	9
						10
						11
						12
	-13,701,828	317,759,682			20,575,306	13
						14
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						40
22,208,843	-13,701,828	362,505,870			72,091,045	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7		81,727,067	410/411		410/411	10,402,945	
8	TOTAL	81,727,067				10,402,945	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
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48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
71,324,122	-8		7
71,324,122			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
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			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Advance on Jobbing Accounts	3,801,709	Various	1,532,983	84,720	2,353,446
2						
3	Accrued Tax Liabilities - LT	24,831,250	Various	205,087,746	256,414,127	76,157,631
4						
5	Miscellaneous Work In Progress	570,541,099	Various	6,377,814,321	6,302,223,551	494,950,329
6						
7	Derivative Conversion - LT	799,176,402	Various	204,880,130		594,296,272
8	(Amort. Period: 12/2006-5/2026)					
9						
10	Income Tax Component of	216,201,542	Various	225,418,482	240,170,402	230,953,462
11	Contributions in Aid of					
12	Construction					
13						
14	SDG&E Liability - LT	106,912,076	Various	29,629,359	6,091,187	83,373,904
15						
16	Misc LT Liabilities	10,786,416	Various	5,913,644		4,872,772
17						
18	Environmental Remediation	149,924,090	Various	12,257,758	1,628,006	139,294,338
19						
20	TDBU Collateral	24,715,563	Various	17,821,598	10,585,370	17,479,335
21						
22	Deferred Revenue	45,727,354	Various	3,353,919		42,373,435
23						
24	QF - ERR Development Costs	142,442,972		26,624,760	1,159,120	116,977,332
25						
26	Miscellaneous:					
27	Deferred Credits	53,884,670		836,724,296	839,518,110	56,678,484
28						
29	Intercompany Executive Compen-	80,988,915		27,189,553	18,769,924	72,569,286
30	sation Plan					
31						
32	CSBU Long-Term Customer	3,725,101		1,037,495	902,365	3,589,971
33	Deposit					
34						
35	COSO Contract Termination Fee				106,375,000	106,375,000
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	2,233,659,159		7,975,286,044	7,783,921,882	2,042,294,997

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
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							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	6,873,424,052	2,787,304,010	2,814,609,957
3	Gas	936,176	249,241	261,743
4	Other	6,492,275		
5	TOTAL (Enter Total of lines 2 thru 4)	6,880,852,503	2,787,553,251	2,814,871,700
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	6,880,852,503	2,787,553,251	2,814,871,700
10	Classification of TOTAL			
11	Federal Income Tax	6,880,852,503	2,787,553,251	2,814,871,700
12	State Income Tax			
13	Local Income Tax			

NOTES

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS						
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits: Account Credited (g)	Debits: Amount (h)	Credits: Account Debited (i)	Credits: Amount (j)	Balance at End of Year (k)	Line No.
							1
			799,690,750		1,361,879,237	7,408,306,592	2
			280,317		278,474	921,831	3
39,975,985	39,631,573		61,267,704		60,483,615	6,052,598	4
39,975,985	39,631,573		861,238,771		1,422,641,326	7,415,281,021	5
							6
							7
							8
39,975,985	39,631,573		861,238,771		1,422,641,326	7,415,281,021	9
							10
39,975,985	39,631,573		861,238,771		1,422,641,326	7,415,281,021	11
							12
							13

NOTES (Continued)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
282	Fully Normalized Deferred Tax	(1,090,207,015)	(1,162,146,512)
282	Property/Non-ISO	(5,756,860,298)	(6,189,165,827)
282	Capitalized software	(25,491,012)	(57,179,648)
282	Audit Rollforward	(865,727)	185,395
	Total Electric	(6,873,424,052)	(7,408,306,592)

Schedule Page: 274 Line No.: 3 Column: k

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS AND OTHER INCOME:			
282	Property/Non-ISO	(936,176)	(921,831)
	Total Gas	(936,176)	(921,831)

Schedule Page: 274 Line No.: 4 Column: k

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER:			
282	Property/Non-ISO	(6,492,275)	(6,052,598)
	Total Other	(6,492,275)	(6,052,598)

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	See Detail Attached	747,744,873	460,445,605	435,257,551
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	747,744,873	460,445,605	435,257,551
10	Gas			
11	See Detail Attached	61,716	35,043	21,510
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	61,716	35,043	21,510
18	TOTAL Other (See Detail Attach	4,351,620		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	752,158,209	460,480,648	435,279,061
20	Classification of TOTAL			
21	Federal Income Tax	752,158,209	460,480,648	435,279,061
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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
		Various	8,592,873	Various	10,613,313	774,953,367	3
							4
							5
							6
							7
							8
			8,592,873		10,613,313	774,953,367	9
							10
		Various	2,507	Various	261	73,003	11
							12
							13
							14
							15
							16
			2,507		261	73,003	17
2,238,526	6,101,051	Various	1,851	Various	7,561	494,805	18
2,238,526	6,101,051		8,597,231		10,621,135	775,521,175	19
							20
2,238,526	6,101,051		8,597,231		10,621,135	775,521,175	21
							22
							23

NOTES (Continued)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
ELECTRIC:			
283	Ad Valorem Lien Date Adj-Electric	(42,051,267)	(53,585,792)
283	Ad Valorem Lien Date Adj-Electric	-	(8,433,048)
283	Refunding & Retirement of Debt	(39,655,122)	(36,020,316)
283	Health Care - IBNR	(1,149,642)	(537,174)
283	Balancing Accounts	(158,026,051)	(366,748,626)
283	Capitalized Software		-
283	Decommissioning	(422,955,253)	(323,139,148)
283	Property/Non-ISO		-
283	Regulatory Assets/Liab		-
283	Temp - Other/Non-ISO	(83,907,538)	13,510,737
	Total Electric	(747,744,873)	(774,953,367)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
GAS AND OTHER INCOME:			
283	Temp - Other/Non-ISO	(61,716)	(73,003)
	Total Gas	(61,716)	(73,003)

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

FERC Account	Description	Balance at Beginning of Year	Balance at End of Year
OTHER:			
283	Temp - Other/Non-ISO	(4,351,620)	(494,805)
	Total Other	(4,351,620)	(494,805)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Demand Reduction and Self-Generation Program	243,680,701	407	36,348,835	61,191,770	268,523,636
2	To track the recorded incremental program costs					
3	and requirement recorded in the Base Revenue					
4	requirement Balancing Account (BRRBA) associated					
5	with SCE's Small Commercial Demand responsiveness					
6	Pilot Program and the Self-Generation Pilot					
7	Program authorized by the CPUC D.01-03-073.					
8						
9	Energy Savings Assistance Program (Formerly Low	127,777,013	Various	72,604,950	65,008,701	120,180,764
10	Income Program Adjustment Mechanism)					
11	To track the Public Purpose Program Charge Funds					
12	allocable to the 1998 low income programs and the					
13	1998 low income energy efficiency program					
14	expenses. Resolution E-3894.					
15						
16	Electric Deferred Refund Account	8,089,769	254	8,110,141	7,921,723	7,901,351
17	To record credits for electric disallowances					
18	ordered by the Commission, Utility Electric					
19	Generation (UEG) shares of gas disallowances					
20	ordered by the Commission or FERC and electric					
21	and UEG amounts resulting from the settlement of					
22	reasonableness disputes at the Commission or FERC					
23						
24	Procurement Energy Efficiency Balancing Acct.	251,642,647	Various	306,401,370	352,103,613	297,344,890
25	To track the difference between actual incremen-					
26	tal procurement-related energy efficiency costs					
27	and authorized procurement-related energy					
28	efficiency revenues per D.03-12-062.					
29						
30	Asset Retirement Obligation (ARO)	1,575,278,872	Various	1,064,217,292	618,583,952	1,129,645,532
31	To establish a regulatory liability for					
32	decommissioning costs collected in rates					
33	for ARO assets.					
34						
35	Transmission Rev Balancing Acct Adjustment	47,872,068	Various	57,775,943	9,903,875	
36	To record transmission revenue credits,					
37	congestion revenue, wheeling revenue, sale of an					
38	FTR revenue and ancillary service expense to					
39	the TRBAA. Athorized by ER18-154-000.					
40						
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Energy Resource Recovery Account		Various	2,948,703	2,948,703	
2	To record SCE's ERRA Revenue, Utility Retained					
3	Generation fuel costs, and purchased power					
4	related expenses, pursuant to D.02-10-062.					
5						
6	Miscellaneous Regulatory Liability	143,122,351	Various	302,822,679	290,766,973	131,066,645
7	To capture various accrued purchased power					
8	agreements D.07-03-005 and other					
9	miscellaneous regulatory liabilities.					
10						
11	Demand Response Program Balancing Account (DRPBA)	133,316,134	Various	266,723,151	205,683,799	72,276,782
12	To record the difference between the actual					
13	capital related revenue requirement and O&M costs					
14	incurred by SCE and the authorized Demand					
15	Response Revenue Requirement approved by the					
16	Commission in D.06-03-024 and in SCE's					
17	General Rate Case (GRC) proceedings					
18	D.14-10-036.					
19						
20	California Solar Inititative Program	167,207,862	Various	48,522,249	12,147,437	130,833,050
21	Balancing Account					
22	To track the recorded incremental California					
23	Solar Initiative Program costs and authorized					
24	distribution revenue requirement recorded in the					
25	Base Revenue Requirement Balancing Account					
26	(BRRBA) associated with SCE's California					
27	Solar Initiative Program, pursuant to D.06-01-024					
28						
29	Post Employment Benefits Other than Pensions	27,472,365	Various	45,227,200	44,315,513	26,560,678
30	(PBOP) Costs Balancing Account					
31	To record the difference between PBOP costs					
32	authorized by the Commission, and recorded					
33	PBOP expenses, pursuant to D.06-05-016.					
34						
35						
36	WECC Statutory Costs	8,058,037	407	9,308,261	10,597,142	9,346,918
37	To record WECC statutory fees being amortized					
38	over 12-month period.					
39						
40						
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Purchase Agreement Administrative Costs Balancing	1,509,909	Various	1,140,159	25,854	395,604
2	Account					
3	To record the difference between SCE's actual					
4	and authorized administrative costs associated					
5	with the Aggregator Managed Portfolio Program in					
6	accordance with D.08-03-017, D.09-08-027,					
7	D13-01-024 and D.14-05-025.					
8						
9	Energy Efficiency Finance Programs Balancing Acct	90,223,836	Various	16,413,527	14,905,753	88,716,062
10	(OBFBA Previously)					
11	To record the difference between actual and					
12	authorized revenue for OBF loan funding, EE Fin-					
13	ance Pilots and ARRA program credit enhancements					
14	in accordance with D.14-10-046.					
15						
16	Medical Balancing Account	23,499,350	Various	85,071,226	94,258,007	32,686,131
17	To record the difference between the authorized					
18	and recorded Medical, Dental, Vision expenses in					
19	accordance with D. 09-03-025.					
20						
21	Misc. On-Bill Financing Regulatory Liability	25,772,726	407	2,952,237	6,209,960	29,030,449
22	To offset 2010-2012 and 2013-2014 OBF loans					
23	and loan repayments, pursuant to D.14-10-046.					
24						
25	REC Regulatory Liability	9,787,066	407	702,483	309,439	9,394,022
26	To record renewable energy credit inventory					
27	as regulatory liability.					
28						
29	Gross Revenue Sharing Mechanism		254	7,901,351	7,901,351	
30	To record the customers' share of certain Other					
31	Operating Revenue (OOR), D.99-09-070.					
32						
33	Electric Program Investment Charge-CEC, SCE	98,652,698	Various	63,425,203	78,100,471	113,327,966
34	and CPUC					
35	To record authorized administrative and program					
36	EPIC revenue requirements and related program					
37	SCE expenses and authorized program payments					
38	to CEC and CPUC per advice letter 2747-E					
39	dated June 25, 2012.					
40						
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Other Regulatory Liability	13,796	Various	20,838	7,042	
2	To record the proceeds from SONGS inventory,					
3	plant and salvage materials from Mesa facility					
4	pending a CPUC final decision and incremental tax					
5	benefit from additional T&D repair deductions.					
6						
7	CARE Balancing Account	13,044,403	Various	48,559,990	43,580,522	8,064,935
8	To reflect in rates, through application of the					
9	Public Purpose Program Charge the costs					
10	associated with the CARE Program as					
11	authorized in various CPUC Decisions,					
12	D.14-08-030.					
13						
14	GHG Revenue Balancing Account	21,930,416	Various	109,278,383	87,347,967	
15	To record the difference between the amount of					
16	GHG revenue actually returned to customers via					
17	rates and bill credits and the actual amount of					
18	GHG revenue SCE receives through consigning					
19	allowances to the cap and trade auction,					
20	pursuant to D.02-10-062.					
21						
22	Statewide ME&O Balancing Account	2,158,899	Various	10,496,150	10,699,758	2,362,507
23	To record the difference between Commission-					
24	authorized Statewide Marketing, Education &					
25	Outreach funding and recorded expenses.					
26						
27	Base Revenue Balancing Account	92,950,508	Various	6,578,165,541	7,113,912,976	628,697,943
28	To record the difference between the commission					
29	authorized base distribution and generation					
30	revenues, pursant to D.04-07-022 (excluding					
31	Z-factor).					
32						
33	Mohave SO2 Allowance Revolving Fund Memo Account	3,655,659			73,507	3,729,166
34	To record the net proceeds from the sale of					
35	sulfurdioxide (SO2) emission allowances					
36	rendered surplus by the closure of the Mohave					
37	Generating Station and to maintain and account					
38	for the revolving fund from the sale and use of					
39	these emission credits, pursuant to					
40	D.13-02-004.					
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Project Development Memo Account	6,619,371	Various	3,936,362	2,882,280	5,565,289
2	To track the difference between Project Develop-					
3	ment Division (PDD) recorded support costs and					
4	PDD forecast, pursuant to D.06-05-016.					
5						
6	Nuclear Decommissioning Adjustment Mechanism		Various	1,115,557	32,826,926	31,711,369
7	To record NDAM revenue, authorized and					
8	recorded costs related to the decommissioning of					
9	San Onofre Nuclear Generating Station and Palo					
10	Verde Nuclear Generating Station, pursuant to					
11	D.03-10-015.					
12						
13	San Onofre Regulatory Liability	4,613,829	Various	123,685,747	119,071,918	
14	To record the difference between San Onofre					
15	Nuclear Generating Station property tax revenue					
16	and costs D.14-11-040, and other authorized					
17	revenue and cost differences.					
18						
19	Energy Settlement Memo Account	10,126,324	182	10,126,322	29,661,313	29,661,315
20	To record refund amounts received by SCE					
21	resulting from FERC investigation settlement					
22	agreements associated with wholesale power					
23	purchases made on behalf of SCE's bundled service					
24	customers, net of litigation costs recorded					
25	in the Litigation Costs Tracking Account,					
26	pursuant to Resolution E-3894.					
27						
28	Financial Reporting Regulatory Liability	18,787,916	Various	141,473,275	396,483,360	273,798,001
29	To record financial / regulatory reserves.					
30						
31	Marine Corps Air Ground Combat Center Memo	1,022,567			20,561	1,043,128
32	Account					
33	To track the after-tax gain on sale of certain					
34	distribution assets located at the United States					
35	Marine Corps Air Ground Combat Center,					
36	Twentynine Palms, California, pursuant to					
37	D.11-09-033.					
38						
39	New System Gen Balancing Account	197,199,497	Various	256,963,708	134,065,459	74,301,248
40	To record the benefits and costs of Power Purchae					
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	agreements (PPAs) and SCE owned peaker generation					
2	unit associated with new generation resources,					
3	pursuant to D.06-07-029.					
4						
5	SONGS Cost of Financing Balancing Account	883,985	Various	1,254,596	370,611	
6	To track 50% of the savings reflected in the					
7	difference between actual cost of financing and					
8	authorized return on SONGS rate base,					
9	pursuant to D.14-11-040.					
10						
11	Tax Accounting Memo Account (TAMA)	262,083,546	Various	353,504,763	226,086,152	134,664,935
12	To track impact on authorized CPUC juris-					
13	dictional revenue requirement as adopted in					
14	D.15-11-021; resulting from income tax accounting					
15	method changes, changes in federal or state law					
16	difference between authorized and recorded					
17	federal and California non-pole loading net					
18	repair deductions, audit findings, or changes					
19	in authorized revenue requirements.					
20						
21	Transmission Access Balancing Account (TACBA)	67,923,425	Various	67,392,306	9,486,091	10,017,210
22	To track the flow through to end-use customers te					
23	net cost-shift billed to SCE by the ISO under the					
24	Transmission Access Charge (TAC), ER17-1345-0000.					
25						
26	Low Carbon Fuel Standard Revenue Balancing	24,035,680	407	2,994,093	81,829,933	102,871,520
27	Account					
28	To record the revenue from the sale of LCFS					
29	credits and set forth the methodology for the					
30	amount of LCFS credit revenue to be returned to					
31	elgible customers pursuant to Decisions (D.)					
32	14-05-021, 14-07-003 and 14-12-083.					
33						
34	Department of Energy Litigation Memorandum	156,990,908	Various	302,560,715	214,226,928	68,657,121
35	Account					
36	To record: (1) SCE's incremental litigation-relad					
37	costs; and (2) proceeds received by SCE from					
38	the federal government for breaching certain					
39	Standard Contracts between SCE and DOE for DOE to					
40	dispose of San Onofre Nuclear Generating					
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/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	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Station (SONGS) spent nuclear fuel.					
2						
3	Green Tariff Shared Renewables Balancing Account	17,470	Various	58,378	49,124	8,216
4	To record the difference between the actual revee					
5	requirements, based on recorded GRSR commodity-					
6	related costs, and the revenues collected from					
7	indiviudal customers electing to participate in e					
8	GRST Program through charges set to collect					
9	these costs.The revenues collected will be based					
10	on a dollar per kWh charged for each kWh of ener					
11	delivered per a customer's GTSR Program					
12	subscription, pursuant to D.15-01-051.					
13						
14	Aliso Canyon Demand Response Program Balancing	1,784,515	Various	862,802	1,409,734	2,331,447
15	Account					
16	To record the difference between the actual costs					
17	incurred by SCE for demand response program					
18	activities to help mitigate a natural gas leak at					
19	the Aliso Canyon Natural Gas Storage Facility					
20	(Aliso Canyon) and the authorized Aliso Canyon					
21	Demand Response funding level approved by the					
22	Commission, D.16-06-029.					
23						
24	Pension Costs Balancing Account	17,952,720	Various	21,726,602	55,295,531	51,521,649
25	To record the difference between pension					
26	costs authorized by the Commission, and					
27	recorded pension expenses, D.06-05-016.					
28						
29	Results Sharing Memorandum Account (RSMA)	20,831,937	Various	83,838,655	83,938,933	20,932,215
30	To track the difference between authorized and					
31	recorded Results Sharing expenses paid out,					
32	pursuant to D.06-05-016.					
33						
34	New Solar Home Partnership Program Balancing Acct	46,315,464			931,294	47,246,758
35	To provide funding for financial incentives for					
36	homeowners, builders, and developers to install					
37	solar energy systems on new, energy efficient					
38	residential dwellings. To record the difference					
39	between the aurthorized Program funding and					
40	disbursements of those funds to the CEC or					
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
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3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	applicants, pursuant to D.16-06-006.					
2						
3	Bilateral Energy & Gas Financial Instruments	78,059,576	407	250,265,938	332,431,318	160,224,956
4	To record the mark-to-market adjustments					
5	related to the financial instruments used to					
6	hedge power purchases and natural gas costs					
7	for utility owned generators.					
8						
9	FERC Formula Rate	94,823,245	Various	296,607,063	381,721,584	179,937,766
10	To record the difference between billed and un-					
11	billed revenue and the recorded transmission					
12	revenue requirement to cover the costs of owning					
13	and operating transmission facilities under ISO					
14	control, per FERC Formula Rate Protocols					
15	ER11-3697.					
16						
17	CPUC Excess Deferred Taxes & Gross-Up TCAJA	2,083,887,022	Various	92,081,970	467	1,991,805,519
18	To record the CPUC-related difference in					
19	accumulated deferred tax balances as a result					
20	of the reduction of the federal income tax rate					
21	by the Tax Cuts And Job Acts to 21% from the					
22	previous 35% and the related tax gross-up that					
23	will be refunded to customers. Excess deferred					
24	taxes subject to the tax normalization require-					
25	ments will be refunded to ratepayers over the					
26	life of the underlying liability that gave rise					
27	to the deferred taxes.					
28						
29	FERC Excess Deferred Taxes-TCAJA	582,299,547	Various	17,481,220		564,818,327
30	To record the FERC-related difference in accumu-					
31	lated deferred tax balances as a result of the					
32	reduction of the federal income tax rate by the					
33	Tax Cuts And Jobs Act to 21% from the previous					
34	35% that will be refunded to customers. Excess					
35	deferred taxes subject to the tax normalization					
36	requirements will be refunded over the life of					
37	the underlying liability that gave rise to the					
38	deferred taxes.					
39						
40						
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	FERC Excess Deferred Tax Gross-Up-TCAJA	226,265,651	Various	6,792,723		219,472,928
2	To record the FERC-related tax gross-up on the					
3	difference in accumulated deferred tax balances					
4	as a result of the reduction of the federal in-					
5	come tax rate by the Tax Cuts And Jobs Act to					
6	21% from the previous 35% that will be					
7	refunded to customers.					
8						
9	Regulatory Liability Pension-SFAS 158	26,587,000	Various	29,379,004	163,041,004	160,249,000
10	To reflect regulatory liability resulting from					
11	the adoption of SFAS 158 Employers'					
12	Accounting for Defined Benefit Pension & Other					
13	Postretirement Plans D.06-05-016.					
14						
15	Solar on Multifamily Affordable Housing Program		407	29,121	55,098,554	55,069,433
16	(SOMAH) Balancing Account (SOMAHBA)					
17	To record the difference between the authorized					
18	SOMAH Program funding levels and all incre-					
19	mental costs associated witht he SOMAH Program,					
20	including costs of conducting a Request for					
21	Approval (RFP), contributions to Program Admin-					
22	istrator (PA) administrative budgets, utility					
23	administration costs and incentive payments					
24	pursuant to Decision (D.)17-12-022.					
25						
26	Public Purpose Programs Adjustments Mechanism		Various	117,087,446	138,887,225	21,799,779
27	To record Public Goods Charge Revenue, PGC ex-					
28	penses authorized in P.U. Code Section 399.8,					
29	and other CPUC Public Purpose Program revenues					
30	and expenses (D.)11-12-038). Programs include:					
31	ESAP, CARE, EPIC, OBF, PEEBA, LCRPBA, & NSHF.					
32						
33	Post Employment Benefits Other than Pensions				24,423,000	24,423,000
34	(PBOP) Regulatory Liability					
35	To reflect the regulatory liability adjustment					
36	for PBOP expense recorded for US GAAP versus					
37	PBOP expense recorded for Utility expense.					
38						
39						
40						
41	TOTAL	7,045,828,280		11,326,356,228	11,622,745,108	7,342,217,160

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	5,021,762,435	4,865,889,031
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	5,933,519,665	5,745,862,868
5	Large (or Ind.) (See Instr. 4)	775,689,306	714,577,218
6	(444) Public Street and Highway Lighting	97,607,163	104,580,008
7	(445) Other Sales to Public Authorities	8,967,710	11,115,798
8	(446) Sales to Railroads and Railways	11,532,083	12,325,988
9	(448) Interdepartmental Sales	215,127	304,581
10	TOTAL Sales to Ultimate Consumers	11,849,293,489	11,454,655,492
11	(447) Sales for Resale	121,877,655	165,557,373
12	TOTAL Sales of Electricity	11,971,171,144	11,620,212,865
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	11,971,171,144	11,620,212,865
15	Other Operating Revenues		
16	(450) Forfeited Discounts	17,746,479	17,711,210
17	(451) Miscellaneous Service Revenues	48,517,705	43,977,762
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	83,380,365	79,426,770
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	554,711,290	467,087,400
22	(456.1) Revenues from Transmission of Electricity of Others	121,439,554	134,205,621
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	825,795,393	742,408,763
27	TOTAL Electric Operating Revenues	12,796,966,537	12,362,621,628

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
30,417,068	29,765,196	4,463,521	4,433,753	2
				3
47,046,265	45,793,686	599,913	594,445	4
8,599,844	7,946,073	31,122	29,814	5
504,865	529,795	17,158	13,600	6
194,716	188,854	4	4	7
87,109	85,229	134	135	8
1,719	2,338	24	22	9
86,851,586	84,311,171	5,111,876	5,071,773	10
4,463,898	6,980,555	11	8	11
91,315,484	91,291,726	5,111,887	5,071,781	12
				13
91,315,484	91,291,726	5,111,887	5,071,781	14

Line 12, column (b) includes $ 269,721,000 of unbilled revenues.

Line 12, column (d) includes 1,575,869 MWH relating to unbilled revenues

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

Footnote: FERC account 9456000 - Other Electric Revenues

Gas Sales	(30,908,340.61)
GHG Allowance Revenue	(389,316,107.71)
ITCC/CIAC Revenues / Grant Amortization	(25,705,217.69)
Interconnection Facilities	(17,820,719.55)
Realized Gain(Loss) LCFS CR (411.8)	(78,366,684.83)
Miscellaneous Others	(12,594,219.62)
Total Other Electric Revenues	(554,711,290.01)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	NONE.				
2					
3					
4					
5					
6					
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40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	NOTE: See Footnote for Symbols					
2						
3	ACCOUNT 440					
4	D	16,277,442	3,145,415,243	2,521,374	6,456	0.1932
5	D @	22,236	2,627,870	2,866	7,759	0.1182
6	D $	397,251	51,070,521	48,070	8,264	0.1286
7	D-CARE	5,920,823	716,744,956	1,017,382	5,820	0.1211
8	D-CARE @	3,368	132,807	566	5,951	0.0394
9	D-CARE $	241,245	10,588,151	33,718	7,155	0.0439
10	D-CARE-CPP	3	236	1	3,000	0.0787
11	DCARE-E	4,147	624,898	344	12,055	0.1507
12	DCARE-E $	25	786	5	5,000	0.0314
13	DCARE-E-N	25	6,309	1	25,000	0.2524
14	D-CARE-N	190,382	13,867,611	24,453	7,786	0.0728
15	D-CARE-N @	13	1,589	1	13,000	0.1222
16	D-CARE-N $	11,732	270,141	1,347	8,710	0.0230
17	D-CARE-N2	9,460	774,889			0.0819
18	D-CARE-N2 $	475	38,562			0.0812
19	D-CARE-SDP	349,259	37,987,390	47,411	7,367	0.1088
20	D-CARE-SDP @	666	16,172	96	6,938	0.0243
21	D-CARE-SDP $	18,082	498,270	2,332	7,754	0.0276
22	D-CARE-SDP-N	18,855	1,095,134	2,365	7,973	0.0581
23	D-CARE-SDP-N$	1,438	22,611	165	8,715	0.0157
24	D-CARE-SDP-N2	867	59,319			0.0684
25	D-CARE-SDPN2$	59	1,867			0.0316
26	D-CARE-SDP-O	12,694	1,515,304	1,712	7,415	0.1194
27	DCARE-SDP-O @	29	1,024	4	7,250	0.0353
28	DCARE-SDP-O $	628	24,819	77	8,156	0.0395
29	DCARE-SDP-O-N	729	39,771	95	7,674	0.0546
30	DCARE-SDP-ON$	29	-59	4	7,250	-0.0020
31	DCARE-SDP-ON2	23	3,212			0.1397
32	D-DL #		1,161			
33	DE	81,486	11,624,481	10,044	8,113	0.1427
34	DE $	970	78,817	99	9,798	0.0813
35	DE-FERA	468	59,852	42	11,143	0.1279
36	DE-FERA $	18	1,226	2	9,000	0.0681
37	DE-FERA-N	20	2,190	2	10,000	0.1095
38	DE-FERA-SDP	100	11,380	11	9,091	0.1138
39	DE-FERA-SDP $	10	677	1	10,000	0.0677
40	DE-FERA-SDP-O	18	2,256	1	18,000	0.1253
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	ACCOUNT 440 CONTINUED					
2	DE-N	3,450	229,848	422	8,175	0.0666
3	DE-N $	44	496	5	8,800	0.0113
4	DE-N2	169	11,538			0.0683
5	DE-N2 $	3	26			0.0087
6	DE-SDP	21,146	2,762,120	2,436	8,681	0.1306
7	DE-SDP @	14	994	1	14,000	0.0710
8	DE-SDP $	202	13,453	21	9,619	0.0666
9	DE-SDP-N	683	34,711	81	8,432	0.0508
10	DE-SDP-N $	31	1,468	3	10,333	0.0474
11	DE-SDP-O	1,001	137,545	120	8,342	0.1374
12	DE-SDP-O-N	11	-2	2	5,500	-0.0002
13	DE-TOU-A	505	56,393	84	6,012	0.1117
14	DETOUAFERASDP	4	327	1	4,000	0.0818
15	DE-TOU-A-N	252	12,001	104	2,423	0.0476
16	DE-TOU-A-N2	559	14,276			0.0255
17	DE-TOU-A-N2 $	20	310			0.0155
18	DE-TOU-A-SDP	334	34,380	44	7,591	0.1029
19	DETOU-A-SDP-N	134	3,894	25	5,360	0.0291
20	DETOU-A-SDPN$	9	6	3	3,000	0.0007
21	DETOU-A-SDPN2	115	3,603			0.0313
22	DETOU-ASDPN2$	15	93			0.0062
23	DETOU-A-SDP-O	25	3,158	2	12,500	0.1263
24	DETOUA-SDPO-N			1		
25	DETOUA-SDPON2	2	25			0.0125
26	DE-TOU-B	3,320	438,045	251	13,227	0.1319
27	DE-TOU-B $	13	894	1	13,000	0.0688
28	DE-TOU-B-CPP	5	625	1	5,000	0.1250
29	DE-TOU-B-N	45	6,144	9	5,000	0.1365
30	DE-TOU-B-N2	60	2,993			0.0499
31	DE-TOU-B-N2 $	1	21			0.0210
32	DE-TOU-B-SDP	2,146	261,194	161	13,329	0.1217
33	DE-TOU-B-SDP$	12	543	1	12,000	0.0453
34	DETOU-B-SDP-N	37	5,188	7	5,286	0.1402
35	DETOU-B-SDPN2	24	564			0.0235
36	DETOU-B-SDP-O	136	17,165	10	13,600	0.1262
37	DETOU-B-SDPON	3	50			0.0167
38	DE-TOUT	313	49,463	23	13,609	0.1580
39	DE-TOUT-N	154	9,149	19	8,105	0.0594
40	DE-TOUT-N2	11	67			0.0061
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	DE-TOUT-SDP	279	41,199	23	12,130	0.1477
2	DE-TOUT-SDP-N	152	10,461	15	10,133	0.0688
3	DE-TOUT-SDPN$	1	45			0.0450
4	DE-TOUTSDP-N2	6	12			0.0020
5	DE-TOUT-SDPON	26	1,380	3	8,667	0.0531
6	D-FERA	110,803	18,357,062	15,110	7,333	0.1657
7	D-FERA @	57	4,891	8	7,125	0.0858
8	D-FERA $	4,412	490,559	508	8,685	0.1112
9	D-FERA-N	8,667	782,655	1,055	8,215	0.0903
10	D-FERA-N $	504	21,474	56	9,000	0.0426
11	D-FERA-N2	402	52,301			0.1301
12	D-FERA-SDP	9,701	1,500,330	1,093	8,876	0.1547
13	D-FERA-SDP @	30	3,421	2	15,000	0.1140
14	D-FERA-SDP $	556	54,657	56	9,929	0.0983
15	D-FERA-SDP-N	723	62,997	79	9,152	0.0871
16	D-FERA-SDP-N$	49	3,451	4	12,250	0.0704
17	D-FERA-SDP-O	444	71,415	53	8,377	0.1608
18	D-FERA-SDP-O$	28	3,253	2	14,000	0.1162
19	DFERA-SDP-O-N	15	609	2	7,500	0.0406
20	DM	78,189	14,849,713	4,927	15,869	0.1899
21	DM @	1,093	118,844	32	34,156	0.1087
22	DM $	869	107,845	38	22,868	0.1241
23	DM-CARE	22	3,353	2	11,000	0.1524
24	DM-CARE-N	1	30			0.0300
25	DM-N	2,634	376,288	190	13,863	0.1429
26	DM-N $	10	146	1	10,000	0.0146
27	DM-N2	580	35,035			0.0604
28	DM-N2 $	2	979			0.4895
29	DMS-1	33,618	5,382,480	254	132,354	0.1601
30	DMS-1 $	238	15,006	3	79,333	0.0631
31	DMS-1-N	1,992	112,470	17	117,176	0.0565
32	DMS-2	406,241	55,406,648	1,203	337,690	0.1364
33	DMS-2 @	1,000	49,887	7	142,857	0.0499
34	DMS-2 $	21,204	1,346,069	49	432,735	0.0635
35	DMS-2-N	29,690	3,070,868	67	443,134	0.1034
36	DMS-2-N $	274	-4,153	1	274,000	-0.0152
37	DMS-2-N2	12,665	926,276			0.0731
38	DMS-3	11,337	1,878,259	69	164,304	0.1657
39	DMS-3 @	269	17,072	2	134,500	0.0635
40	DMS-3 $	585	58,074	1	585,000	0.0993
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	ACCOUNT 440 CONTINUED					
2	DMS-3-N	1,273	229,670	1	1,273,000	0.1804
3	DMS-3-P	971	137,168	2	485,500	0.1413
4	DMS-3-P-N	1,320	18,271	2	660,000	0.0138
5	DMS-3-P-N2	641	9,590			0.0150
6	D-N	1,143,119	110,037,534	142,982	7,995	0.0963
7	D-N @	76	3,762	8	9,500	0.0495
8	D-N $	51,139	1,670,950	5,299	9,651	0.0327
9	D-N2	52,394	5,133,117			0.0980
10	D-2N @	3	-14			-0.0047
11	D-N2 $	2,206	306,076			0.1387
12	D-PG-S	4	578	1	4,000	0.1445
13	D-SDP	1,013,282	179,386,413	125,789	8,055	0.1770
14	D-SDP @	3,915	378,219	468	8,365	0.0966
15	D-SDP $	43,384	4,725,201	4,706	9,219	0.1089
16	D-SDP-CPP	3	530			0.1767
17	D-SDP-N	101,131	8,012,126	12,533	8,069	0.0792
18	D-SDP-N @	25	1,910	2	12,500	0.0764
19	D-SDP-N $	6,701	165,444	781	8,580	0.0247
20	D-SDP-N2	4,398	371,483			0.0845
21	D-SDP-N2 @	1	-60			-0.0600
22	D-SDP-N2 $	293	43,419			0.1482
23	D-SDP-O	41,615	7,785,668	5,178	8,037	0.1871
24	D-SDP-O @	100	10,427	13	7,692	0.1043
25	D-SDP-O $	1,141	139,120	117	9,752	0.1219
26	D-SDP-O-N	4,539	380,404	610	7,441	0.0838
27	D-SDP-O-N $	186	4,028	23	8,087	0.0217
28	D-SDP-O-N2	201	16,366			0.0814
29	D-SDP-O-N2 $	10	1,607			0.1607
30	DTA-CARE-SDP	1,377	133,670	210	6,557	0.0971
31	DTACARE-SDP @	2	3			0.0015
32	DTACARE-SDP $	18	762	3	6,000	0.0423
33	DTACARE-SDP-N	810	32,800	517	1,567	0.0405
34	DTACARE-SDPN$	20	137	26	769	0.0069
35	DTACARE-SDPN2	3,135	89,100			0.0284
36	DTACARESDPN2$	168	1,438			0.0086
37	DTACARE-SDP-O	42	4,321	6	7,000	0.1029
38	DTACARESDPO-N	58	2,185	28	2,071	0.0377
39	DTACARESDPON$			1		
40	DTACARESDPON2	153	4,159			0.0272
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	DTACARSDPON2$	4	19			0.0048
2	DTAFERA-SDPN2	157	3,033			0.0193
3	DTAFERASDPN2$	6	75			0.0125
4	DTAFERASDPON	9	46	2	4,500	0.0051
5	DTAFERASDPON2	3	5	187	16	0.0017
6	DTA-SDP-O-N	610	23,588			0.0387
7	DTA-SDP-O-N2	839	30,216			0.0360
8	DTA-SDP-O-N2$	47	1,156			0.0246
9	DTB-CARE-SDP	6,700	774,595	501	13,373	0.1156
10	DTB-CARE-SDP$	78	2,730	5	15,600	0.0350
11	DTBCARE-SDP-N	438	36,057	37	11,838	0.0823
12	DTBCARESDP-N$	3	221	1	3,000	0.0737
13	DTBCARE-SDPN2	106	11,395			0.1075
14	DTBCARESDPN2$	8	96			0.0120
15	DTBCARE-SDP-O	170	20,854	13	13,077	0.1227
16	DTBCARE-SDPO$	10	423	1	10,000	0.0423
17	DTBCARESDPON2	2	54			0.0270
18	DTB-SDP-O-N	284	38,957	27	10,519	0.1372
19	DTB-SDP-O-N2	54	1,730			0.0320
20	D-TOU-1-P	7	-15,835	1	7,000	-2.2621
21	D-TOU1-P-CARE	6	-9,000	1	6,000	-1.5000
22	D-TOU1-P-FERA		-31			
23	DTOU1PFERASDP		-204			
24	D-TOU-1-P-SDP	-4	-7,680			1.9200
25	DTOU1PSDPCARE	-5	-5,548			1.1096
26	D-TOU1-P-SDPO		-321			
27	DTOU1PSDP-O-C		-18			
28	D-TOU-2					
29	D-TOU-2-P	-7	-21,445	1	-7,000	3.0636
30	D-TOU2-P-CARE	2	-14,904	1	2,000	-7.4520
31	D-TOU2-P-FERA		-652			
32	DTOU2PFERASDP		-44			
33	D-TOU-2-P-SDP	-19	-14,325			0.7539
34	DTOU2PSDPCARE		-6,599			
35	D-TOU2-P-SDPO		-457			
36	DTOU2PSDP-O-C	-2	-207			0.1035
37	D-TOU-3-P		-15,807	2		
38	D-TOU3-P-CARE	6	-21,800	2	3,000	-3.6333
39	DTOU3PFERASDP		-4,704			
40	DTOU3PSDPCARE		-4,283			
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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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	D-TOU-A	83,231	13,087,582	15,804	5,266	0.1572
3	D-TOU-A @	3	26			0.0087
4	D-TOU-A $	341	41,516	38	8,974	0.1217
5	D-TOU-A-CARE	17,901	1,837,314	4,214	4,248	0.1026
6	D-TOU-A-CARE$	49	2,695	8	6,125	0.0550
7	DTOU-A-CARE-N	3,608	173,808	5,066	712	0.0482
8	DTOU-A-CAREN$	43	1,674	238	181	0.0389
9	DTOU-A-CAREN2	31,166	911,661			0.0293
10	DTOU-ACAREN2$	1,709	21,614			0.0126
11	D-TOU-A-FERA	378	55,231	61	6,197	0.1461
12	D-TOU-A-FERA$	2	211			0.1055
13	D-TOUA-FERA-N	274	11,321	260	1,054	0.0413
14	D-TOUA-FERAN$	6	-59	17	353	-0.0098
15	D-TOUA-FERAN2	1,659	56,779			0.0342
16	D-TOUAFERAN2$	128	2,214			0.0173
17	DTOUAFERASDP	57	6,835	10	5,700	0.1199
18	DTOUAFERASDPN	17	726	22	773	0.0427
19	D-TOU-A-N	63,049	3,617,692	36,701	1,718	0.0574
20	D-TOU-A-N @			1		
21	D-TOU-A-N $	690	7,916	1,104	625	0.0115
22	D-TOU-A-N2	213,115	9,002,764			0.0422
23	D-TOU-A-N2 @	15	290			0.0193
24	D-TOU-A-N2 $	9,261	242,000			0.0261
25	D-TOU-A-SDP	11,706	1,573,095	1,860	6,294	0.1344
26	D-TOU-A-SDP @	6	374	1	6,000	0.0623
27	D-TOU-A-SDP $	41	3,936	5	8,200	0.0960
28	D-TOU-A-SDP-N	10,945	569,776	3,356	3,261	0.0521
29	D-TOU-A-SDPN$	152	4,404	146	1,041	0.0290
30	D-TOUA-SDP-N2	15,980	491,881			0.0308
31	D-TOUA-SDPN2@	1	16			0.0160
32	D-TOUA-SDPN2$	1,126	24,346			0.0216
33	D-TOU-A-SDP-O	448	69,187	65	6,892	0.1544
34	D-TOU-B	483,953	83,089,359	28,503	16,979	0.1717
35	D-TOU-B @	155	15,712	11	14,091	0.1014
36	D-TOU-B $	8,339	877,585	213	39,150	0.1052
37	D-TOU-B-CARE	28,752	3,495,324	2,159	13,317	0.1216
38	D-TOU-B-CARE@	10	411	1	10,000	0.0411
39	D-TOU-B-CARE$	673	29,423	31	21,710	0.0437
40	DTOU-B-CARE-N	2,462	213,583	198	12,434	0.0868
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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1	ACCOUNT 440 CONTINUED					
2	DTOU-B-CAREN$	50	979	7	7,143	0.0196
3	DTOU-B-CAREN2	555	26,746			0.0482
4	DTOU-BCAREN2$	45	823			0.0183
5	D-TOU-B-FERA	1,902	285,723	117	16,256	0.1502
6	D-TOUB-FERA $	15	1,305	1	15,000	0.0870
7	D-TOUB-FERA-N	174	44,786	19	9,158	0.2574
8	D-TOUB-FERA-N$	15	258	2	7,500	0.0172
9	D-TOUB-FERAN2	64	5,350			0.0836
10	DTOUBFERADN2	11	243			0.0221
11	D-TOUBFERASDP	383	55,350	26	14,731	0.1445
12	DTOUBFERASDPN	48	4,022	5	9,600	0.0838
13	DTOUBFERASDPO	23	3,550	1	23,000	0.1543
14	D-TOU-B-N	38,916	4,881,651	3,300	11,793	0.1254
15	D-TOU-B-N $	787	21,288	50	15,740	0.0270
16	D-TOU-B-N2	9,935	732,426			0.0737
17	D-TOU-B-N2 $	241	33,982			0.1410
18	D-TOU-B-SDP	68,324	11,134,637	5,175	13,203	0.1630
19	D-TOU-B-SDP @	107	8,964	6	17,833	0.0838
20	D-TOU-B-SDP $	1,029	92,043	62	16,597	0.0894
21	D-TOUB-SDPCPP	8	1,480	1	8,000	0.1850
22	D-TOU-B-SDP-N	5,510	629,448	479	11,503	0.1142
23	D-TOU-B-SDPN$	220	2,993	12	18,333	0.0136
24	D-TOU-B-SDPN2	1,134	76,764			0.0677
25	D-TOUB-SDPN2$	42	1,685			0.0401
26	D-TOU-B-SDP-O	3,196	555,248	253	12,632	0.1737
27	D-TOU-B-SDPO$	41	4,244	2	20,500	0.1035
28	D-TOU-EV-1	3,116	469,119	841	3,705	0.1506
29	D-TOU-EV-1 @	15	1,928	1	15,000	0.1285
30	D-TOU-EV-1 $	42	5,159	5	8,400	0.1228
31	D-TOU-EV-1-N	10	721	4	2,500	0.0721
32	D-TOU-EV-1-N2	1	27			0.0270
33	D-TOUT	35,988	7,760,288	2,601	13,836	0.2156
34	D-TOUT @	69	9,283	5	13,800	0.1345
35	D-TOUT $	658	98,220	33	19,939	0.1493
36	D-TOUT-CARE	9,438	1,422,297	725	13,018	0.1507
37	D-TOUT-CARE @	6	312	1	6,000	0.0520
38	D-TOUT-CARE $	301	20,606	23	13,087	0.0685
39	D-TOUT-CARE-N	4,726	328,948	566	8,350	0.0696
40	D-TOUT-CAREN$	223	10,521	21	10,619	0.0472
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
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1	ACCOUNT 440 CONTINUED					
2	D-TOUT-CAREN2	587	28,877			0.0492
3	D-TOUTCAREN2$	8	352			0.0440
4	D-TOUT-CPP-N	4	-25	1	4,000	-0.0063
5	D-TOUT-C-SDP	3,209	460,573	238	13,483	0.1435
6	D-TOUT-C-SDP$	141	8,261	10	14,100	0.0586
7	DTOUT-C-SDP-N	941	48,186	108	8,713	0.0512
8	DTOUT-C-SDPN$	73	1,404	8	9,125	0.0192
9	DTOUT-C-SDPN2	110	7,268			0.0661
10	DTOUT-CSDPN2$	9	66			0.0073
11	DTOUT-C-SDP-O	28	4,182	2	14,000	0.1494
12	DTOUT-C-SDPO$	15	1,014	1	15,000	0.0676
13	DTOUTC-SDPO-N	48	3,165	5	9,600	0.0659
14	DTOUTC-SDPON$	2	16			0.0080
15	DTOUTC-SDPON2	1	1			0.0010
16	DTOUTCSDPON2$	1	5			0.0050
17	D-TOUT-N	73,584	6,565,617	8,513	8,644	0.0892
18	D-TOUT-N $	1,792	55,994	168	10,667	0.0312
19	D-TOUT-N2	6,398	433,827			0.0678
20	D-TOUT-N2 $	126	13,213			0.1049
21	D-TOUT-SDP	9,305	1,861,307	711	13,087	0.2000
22	D-TOUT-SDP $	203	25,950	17	11,941	0.1278
23	D-TOUT-SDP-N	13,066	1,090,498	1,483	8,811	0.0835
24	D-TOUT-SDP-N$	356	13,994	40	8,900	0.0393
25	D-TOUT-SDP-N2	1,024	87,741			0.0857
26	D-TOUT-SDPN2$	42	1,425			0.0339
27	D-TOUT-SDP-O	215	45,550	18	11,944	0.2119
28	DTOUT-SDP-O-N	489	49,970	57	8,579	0.1022
29	D-TOUT-SDPON2	47	742			0.0158
30	DTU1PFERASDPO		-35			
31	DTU3PFERASDPO		-49			
32	DTU3PSDPOCARE		-146			
33	DTU-TEV-SDP-N		-10			
34	DWL-A	1,914	557,602	94	20,362	0.2913
35	DWL-A @	12	3,630	1	12,000	0.3025
36	DWL-B	21	2,997			0.1427
37	DWL-B $	29	2,909	1	29,000	0.1003
38	DWL-C	101	15,546	2	50,500	0.1539
39	GS-1	75	16,249	18	4,167	0.2167
40	GS-2	43	13,104	1	43,000	0.3047
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
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1	ACCOUNT 440 CONTINUED					
2	GS-TOU-EV-3A	-1	-122			0.1220
3	OL-1-ALLNITE	2,301	624,954	2,957	778	0.2716
4	OL-1ALLNITE@		112	1		
5	OL-1ALLNITE $	62	13,985	101	614	0.2256
6	TD-4-C-SDP	3,675	407,164	594	6,187	0.1108
7	TD-4-C-SDP-N	117	11,129	13	9,000	0.0951
8	TD-4-C-SDP-N2	13	84			0.0065
9	TD-4-C-SO	80	9,485	14	5,714	0.1186
10	TD-4-C-SO-N	14	1,754	2	7,000	0.1253
11	TD-4-C-SO-N2	4	127			0.0318
12	TD-4-F-SDP	122	18,422	16	7,625	0.1510
13	TD-4-F-SDP-N	2	2			0.0010
14	TD-4-F-SDP-N2	1	1			0.0010
15	TD-4-F-SO	13	2,263	2	6,500	0.1741
16	TD-5-C-SDP	3,640	397,173	598	6,087	0.1091
17	TD-5-C-SDP-N	90	3,358	13	6,923	0.0373
18	TD-5-C-SDP-N2	16	644			0.0403
19	TD-5-C-SO	150	18,430	24	6,250	0.1229
20	TD-5-F-SDP	77	11,389	11	7,000	0.1479
21	TD-5-F-SDP-N	10	1,823	2	5,000	0.1823
22	TD-5-F-SDP-N2	2	57			0.0285
23	TD-5-F-SO	14	2,513	2	7,000	0.1795
24	TGS1-A	216,675	43,389,671	43,461	4,986	0.2003
25	TGS1-A @	1,752	175,168	206	8,505	0.1000
26	TGS1-A $	6,801	846,081	1,422	4,783	0.1244
27	TGS1-A-APSE	106	16,987	11	9,636	0.1603
28	TGS1-A-C	1	201			0.2010
29	TGS1-A-C $		41			
30	TGS1-A-CPP	25	4,199	3	8,333	0.1680
31	TGS1-A-N	1,169	110,223	96	12,177	0.0943
32	TGS1-A-N $	28	758	3	9,333	0.0271
33	TGS1-A-S-N2	117	15,697			0.1342
34	TGS1-A-S-N2 $	12	886			0.0738
35	TGS1-B	31,829	4,193,078	1,901	16,743	0.1317
36	TGS1-B @	1,224	81,604	74	16,541	0.0667
37	TGS1-B $	1,125	74,011	64	17,578	0.0658
38	TGS1-B-C	76	5,792	1	76,000	0.0762
39	TGS1-B-N	104	10,602	5	20,800	0.1019
40	TGS1-B-N2	15	1,238			0.0825
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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	ACCOUNT 440 CONTINUED					
2	TGS1-RTP	2	888	1	2,000	0.4440
3	TGS2A-N2-S		-96			
4	TGS2A-N-S	-1	-538			0.5380
5	TGS2A-S	-8	-2,691			0.3364
6	TGS2B-APSE-S	56	10,691	1	56,000	0.1909
7	TGS2B-C-S	121	12,203	1	121,000	0.1009
8	TGS2B-N2-S	21	4,172			0.1987
9	TGS2B-N-S	168	44,122	4	42,000	0.2626
10	TGS2B-S	30,175	4,871,175	265	113,868	0.1614
11	TGS2B-S @	974	77,890	7	139,143	0.0800
12	TGS2B-S $	981	102,221	9	109,000	0.1042
13	TOU-D-4	536,227	102,614,462	86,820	6,176	0.1914
14	TOU-D-4 $	36	4,466	1	36,000	0.1241
15	TOU-D-4-C	110,319	12,929,210	24,525	4,498	0.1172
16	TOU-D-4-C-N	1,143	84,159	195	5,862	0.0736
17	TOU-D-4-C-N2	145	7,382			0.0509
18	TOU-D-4-F	1,833	296,023	323	5,675	0.1615
19	TOU-D-4-F-N	43	5,617	6	7,167	0.1306
20	TOU-D-4-F-N2	4	116			0.0290
21	TOU-D-4-N	18,756	2,175,151	2,526	7,425	0.1160
22	TOU-D-4-N2	2,616	175,580			0.0671
23	TOU-D-4-SDP	33,633	5,761,657	4,476	7,514	0.1713
24	TOU-D-4-SDP $	22	1,896	2	11,000	0.0862
25	TOU-D-4-SDP-N	1,717	164,042	224	7,665	0.0955
26	TOU-D-4-SDPN2	236	20,833			0.0883
27	TOU-D-4-SDPO	1,197	226,047	156	7,673	0.1888
28	TOU-D-4SDPON	81	9,070	11	7,364	0.1120
29	TOU-D-4SDPON2	17	1,245	88,456		0.0732
30	TOU-D-5	543,882	103,909,330	2	271,941,000	0.1911
31	TOU-D-5 $	36	4,511	25,146	1	0.1253
32	TOU-D-5-C	112,701	13,192,864	230	490,004	0.1171
33	TOU-D-5-C-N	1,472	108,634			0.0738
34	TOU-D-5-C-N2	180	8,809			0.0489
35	TOU-D-5-F	1,846	296,998	328	5,628	0.1609
36	TOU-D-5-F-N	46	7,504	7	6,571	0.1631
37	TOU-D-5-F-N2	8	501			0.0626
38	TOU-D-5-N	19,524	2,337,205	2,571	7,594	0.1197
39	TOU-D-5-N2	2,701	187,929			0.0696
40	TOU-D-5-SDP	35,938	6,115,467	4,842	7,422	0.1702
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	TOU-D-5-SDP $	5	507	1	5,000	0.1014
3	TOU-D-5-SDP-N	1,677	180,403	231	7,260	0.1076
4	TOU-D-5-SDPN2	292	11,487			0.0393
5	TOU-D-5-SDPO	1,348	251,899	178	7,573	0.1869
6	TOU-D-5SDPON	52	2,533	9	5,778	0.0487
7	TOU-D-5SDPON2	13	510			0.0392
8	TOU-DE-4	2,649	381,631	353	7,504	0.1441
9	TOU-DE-4-F	1	39	1	1,000	0.0390
10	TOU-DE-4-N	41	5,433	5	8,200	0.1325
11	TOU-DE-4-N2	9	972			0.1080
12	TOU-DE-4-SDP	590	74,781	73	8,082	0.1267
13	TOU-DE-4SDPN	14	81	2	7,000	0.0058
14	TOU-DE-4SDPN2	1	-5			-0.0050
15	TOU-DE-4SDPO	22	2,829	4	5,500	0.1286
16	TOU-DE-5	2,536	361,730	348	7,287	0.1426
17	TOU-DE-5-F	9	1,249	1	9,000	0.1388
18	TOU-DE-5-N	34	2,549	5	6,800	0.0750
19	TOU-DE-5-N2	14	947			0.0676
20	TOU-DE-5-SDP	714	88,508	92	7,761	0.1240
21	TOU-DE-5SDPN2	5	47			0.0094
22	TOU-DE5-SDPO	26	3,774	3	8,667	0.1452
23	TPA2-A	200	45,972	11	18,182	0.2299
24	TPA2-A-N	21	5,029	1	21,000	0.2395
25	TPA2-A-N2	2	477			0.2385
26	TPA2-B	763	169,313	90	8,478	0.2219
27	TPA2-B $	25	9,026	6	4,167	0.3610
28	TPA2-B-API	123	16,146	1	123,000	0.1313
29	TPA2-B-N		356			
30	TPA2-B-S-N	11	2,340	1	11,000	0.2127
31	TPA2-B-S-N2	1	729			0.7290
32	TPA3-B	1,241	111,198	1	1,241,000	0.0896
33	TPA3-B-SEC	769	65,839			0.0856
34						
35	OTHER ADJUSTMENTS		-334,302			
36	TOTAL ACCOUNT 440	29,865,172	4,891,952,905	4,463,532	6,691	0.1638
37						
38						
39						
40						
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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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					
2	AL-2	135,708	10,417,044	7,959	17,051	0.0768
3	AL-2 @	4,829	127,680	70	68,986	0.0264
4	AL-2 $	4,312	149,541	395	10,916	0.0347
5	D	-237	-57,662	1	-237,000	0.2433
6	D $		4			
7	D-CARE		4			
8	DM	-1	-316			0.3160
9	DMS-1	-2	272			-0.1360
10	DMS-2	-22	1,374			-0.0625
11	DMS-2-N $	-2	614			-0.3070
12	DMS-3	136	25,794	1	136,000	0.1897
13	D-SDP	-9	-2,284			0.2538
14	D-TOU-A-N2	-9	-121			0.0134
15	D-TOU-B	-7	-1,012			0.1446
16	D-TOU-EV-1		-63			
17	GS-1	7,163	1,178,979	491	14,589	0.1646
18	GS-1 $	5	511	1	5,000	0.1022
19	GS-2	7,681	1,289,505	108	71,120	0.1679
20	GS-2 @	47	564			0.0120
21	GS-TOU-EV-3A	180	35,826	37	4,865	0.1990
22	GSTOU-EV-3A $	5	482	1	5,000	0.0964
23	GS-TOU-EV-3B	159	41,949	23	6,913	0.2638
24	GS-TOU-EV-3B@	2	360	1	2,000	0.1800
25	GS-TOU-EV-3B$	7	1,242			0.1774
26	GS-TOU-EV3BN2		348			
27	GS-TOU-EV-4 $	216	60,669	5	43,200	0.2809
28	GS-TOU-EV4-P$	238	40,171			0.1688
29	LS-1-ALLNITE	15,977	4,862,626	2,931	5,451	0.3044
30	LS1-ALLNITE@	126	28,643	7	18,000	0.2273
31	LS1-ALLNITE $	840	160,624	61	13,770	0.1912
32	LS-1-MIDNITE	8	2,605	1	8,000	0.3256
33	LS1-TAP	121	30,609			0.2530
34	LS-2	2,428	218,902	238	10,202	0.0902
35	LS-2 @	9	417	2	4,500	0.0463
36	LS-2 $	57	2,208	9	6,333	0.0387
37	LS-2-B	33	4,822	11	3,000	0.1461
38	LS-3	2,484	226,011	507	4,899	0.0910
39	LS-3 @	19	1,543	8	2,375	0.0812
40	LS-3 $	41	1,896	9	4,556	0.0462
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	LS-3-B	20,213	1,711,613	2,747	7,358	0.0847
3	LS-3-B @	1,143	43,750	143	7,993	0.0383
4	LS-3-B $	411	19,053	82	5,012	0.0464
5	OL-1-ALLNITE	8,840	2,014,506	5,342	1,655	0.2279
6	OL-1ALLNITE@	81	12,017	35	2,314	0.1484
7	OL-1ALLNITE $	206	37,716	164	1,256	0.1831
8	OL-1-MIDNITE		46	1		
9	PA-1	-277	-56,773	6	-46,167	0.2050
10	PA-2	1,066	160,182	3	355,333	0.1503
11	T8A-S-P	6,014	561,689	1	6,014,000	0.0934
12	T8A-S-S		810			
13	T8A-S-T	9,669	621,542	1	9,669,000	0.0643
14	T8BAPSECPPN-S	882	157,416	1	882,000	0.1785
15	T8-RTP-BIPN2P	950	143,124			0.1507
16	T8-RTP-BIPN-P	5,083	803,634	1	5,083,000	0.1581
17	T8-RTP-BIPN-T	112,284	10,555,291			0.0940
18	T8-RTP-BIP-P	41,038	7,230,471	6	6,839,667	0.1762
19	T8-RTP-BIP-S	68,963	9,621,689	16	4,310,188	0.1395
20	T8-RTP-BIP-T	134,837	10,984,458	3	44,945,667	0.0815
21	T8-RTP-DL-P #		1,391			
22	T8-RTP-DL-S #		54,940			
23	T8-RTP-P	41,135	7,087,034	13	3,164,231	0.1723
24	T8-RTP-S	71,563	12,310,304	37	1,934,135	0.1720
25	T8-RTP-S-P	4,870	554,685	2	2,435,000	0.1139
26	T8-RTP-S-S		270			
27	T8-RTP-S-T	64,892	5,017,483	3	21,630,667	0.0773
28	T8-RTP-T	17,695	1,653,898	1	17,695,000	0.0935
29	T8-S-APSE-P	70,476	7,983,458	3	23,492,000	0.1133
30	T8-S-APSE-P @	7,530	438,779	1	7,530,000	0.0583
31	T8-S-APSE-S	1,935	372,846	2	967,500	0.1927
32	T8-S-BIP-P	32,105	3,037,047	5	6,421,000	0.0946
33	T8-S-BIP-S	20,943	2,173,201	3	6,981,000	0.1038
34	T8-S-BIP-S @	9,215	253,101	1	9,215,000	0.0275
35	T8-S-BIP-T	863,148	55,685,126	5	172,629,600	0.0645
36	T8-S-BIP-T @	182,497	1,166,858	2	91,248,500	0.0064
37	T8-S-P	352,543	43,578,175	52	6,779,673	0.1236
38	T8-S-P @	59,987	3,015,939	10	5,998,700	0.0503
39	T8-S-P $	4,565	-925,030			-0.2026
40	T8-S-S	123,754	15,540,520	33	3,750,121	0.1256
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	T8-S-S @	22,209	1,229,591	5	4,441,800	0.0554
3	T8-S-T	1,285,488	103,437,654	90	14,283,200	0.0805
4	T8-S-T @	168,994	4,777,644	13	12,999,538	0.0283
5	TC-1	46,530	8,463,108	12,565	3,703	0.1819
6	TC-1 @	2,161	229,819	437	4,945	0.1063
7	TC-1 $	2,482	330,192	868	2,859	0.1330
8	TG2BAPSECPN2P	36	4,640			0.1289
9	TG2BAPSECPN2S	8	1,481			0.1851
10	TG2BAPSECPPNP	17	2,833			0.1666
11	TG2BAPSECPPNS	116	16,797	1	116,000	0.1448
12	TG3BAPSECPN2P	174	27,485			0.1580
13	TG3BAPSECPN2S	545	111,738			0.2050
14	TG3BAPSECPPNP	81	11,583	2	40,500	0.1430
15	TG3BAPSECPPNS	1,857	318,215	7	265,286	0.1714
16	TG3BAPSECPPS$		-1,997			
17	TGS1-A	3,979,897	704,143,798	385,401	10,327	0.1769
18	TGS1-A @	38,169	3,437,837	2,787	13,695	0.0901
19	TGS1-A $	165,173	16,351,670	17,285	9,556	0.0990
20	TGS1-A-APSE	55,150	8,847,230	3,899	14,145	0.1604
21	TGS1-A-APSE @	1,543	123,331	112	13,777	0.0799
22	TGS1-A-APSE $	2,114	162,557	185	11,427	0.0769
23	TGS1-A-APSE-C	8	856			0.1070
24	TGS1AAPSE-CPP	5	888	1	5,000	0.1776
25	TGS1-A-APSE-N	663	67,105	45	14,733	0.1012
26	TGS1A-APSE-N$	29	524	3	9,667	0.0181
27	TGS1-A-APSEN2	122	7,154			0.0586
28	TGS1-AAPSEN2$	18	436			0.0242
29	TGS1-A-APSE-P	33	4,962	1	33,000	0.1504
30	TGS1-A-C	1,341	153,482	65	20,631	0.1145
31	TGS1-A-C $	22	496			0.0225
32	TGS1-A-C-N	95	10,394	1	95,000	0.1094
33	TGS1-A-CPP	921	148,372	55	16,745	0.1611
34	TGS1-A-CPP-N		5			
35	TGS1-A-CPP-NS		56			
36	TGS1-A-N	20,212	2,247,323	1,530	13,210	0.1112
37	TGS1-A-N $	1,086	48,263	81	13,407	0.0444
38	TGS1-A N2 @	29	1,493			0.0515
39	TGS1-A-P	2,986	424,363	58	51,483	0.1421
40	TGS1-A-P @	64	4,555	2	32,000	0.0712
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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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	TGS1-A-P $	155	14,075	10	15,500	0.0908
2	TGS1-A-P-CPP	154	24,023	19	8,105	0.1560
3	TGS1-A-P-CPP$	14	1,132			0.0809
4	TGS1-A-S-N2	4,640	483,554			0.1042
5	TGS1-A-S-N2 $	236	12,239			0.0519
6	TGS1-A-T	-10	-818	1	-10,000	0.0818
7	TGS1-A-T @		262	1		
8	TGS1-A-T $	10	802	1	10,000	0.0802
9	TGS1-B	1,177,869	151,231,304	42,403	27,778	0.1284
10	TGS1-B @	105,263	7,488,150	10,180	10,340	0.0711
11	TGS1-B $	48,699	2,916,368	2,057	23,675	0.0599
12	TGS1-B-APSE	19,873	2,580,251	470	42,283	0.1298
13	TGS1-B-APSE @	247	14,279	7	35,286	0.0578
14	TGS1-B-APSE $	1,118	60,528	26	43,000	0.0541
15	TGS1-B-APSE-C	28	3,095	1	28,000	0.1105
16	TGS1-B-APSE-N	-33	3,342	3	-11,000	-0.1013
17	TGS1-B-APSEN2	27	3,127			0.1158
18	TGS1-B-C	304	28,987	9	33,778	0.0954
19	TGS1-B-C $	24	319			0.0133
20	TGS1-B-N	3,200	373,521	125	25,600	0.1167
21	TGS1-B-N @	27	2,171	1	27,000	0.0804
22	TGS1-B-N $	181	12,723	7	25,857	0.0703
23	TGS1-B-N2	835	84,077			0.1007
24	TGS1-B-N2 @	3	386			0.1287
25	TGS1-B-N2 $	8	546			0.0683
26	TGS1-B-P-STBY	177	23,527	5	35,400	0.1329
27	TGS1-B-S-STBY	11	3,496	4	2,750	0.3178
28	TGS1-RTP	187	32,242	18	10,389	0.1724
29	TGS1-RTPS	5	1,595	1	5,000	0.3190
30	TGS2AAPSE-C-S	71	9,067	1	71,000	0.1277
31	TGS2AAPSE-N2S	1,270	206,592			0.1627
32	TGS2AAPSE-N-S	2,675	495,760	43	62,209	0.1853
33	TGS2A-APSENS$	47	8,235	1	47,000	0.1752
34	TGS2A-APSE-S	139,649	29,852,573	1,488	93,850	0.2138
35	TGS2A-APSE-S@	3,166	391,476	21	150,762	0.1237
36	TGS2A-APSE-S$	7,234	962,677	84	86,119	0.1331
37	TGS2A-C-N-S	32	3,189			0.0997
38	TGS2A-C-N-S $	50	2,679	1	50,000	0.0536
39	TGS2A-C-S	950	103,593	4	237,500	0.1090
40	TGS2A-DL-S #		774			
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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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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	TGS2A-N2-S	5,503	972,306			0.1767
3	TGS2A-N2-S$	267	41,525			0.1555
4	TGS2A-N-S	15,581	2,713,467	203	76,754	0.1742
5	TGS2A-N-S $	792	116,306	15	52,800	0.1469
6	TGS2A-P	4,619	850,829	31	149,000	0.1842
7	TGS2A-P $	87	9,720	1	87,000	0.1117
8	TGS2A-S	1,566,569	310,765,726	17,174	91,217	0.1984
9	TGS2A-S @	24,763	2,478,603	137	180,752	0.1001
10	TGS2A-S $	60,711	7,842,062	717	84,674	0.1292
11	TGS2A-STDBY	426	88,486	6	71,000	0.2077
12	TGS2BAPSECPPP	344	46,690	1	344,000	0.1357
13	TGS2BAPSECPPS	7,597	1,243,117	26	292,192	0.1636
14	TGS2BAPSE-C-S	372	46,420	4	93,000	0.1248
15	TGS2BAPSE-CS$	226	5,416	1	226,000	0.0240
16	TGS2BAPSEN2S@	615	51,233			0.0833
17	TGS2BAPSE-N-S	5,875	1,047,322	58	101,293	0.1783
18	TGS2BAPSEN-S@	8,580	663,849	32	268,125	0.0774
19	TGS2B-APSE-P	745	109,558	2	372,500	0.1471
20	TGS2B-APSE-P$	197	12,936	1	197,000	0.0657
21	TGS2B-APSE-S	239,242	41,930,795	1,718	139,256	0.1753
22	TGS2B-APSE-S@	145,215	9,786,419	485	299,412	0.0674
23	TGS2B-APSE-S$	9,889	985,195	80	123,613	0.0996
24	TGS2BAPSE-SN2	1,169	206,968			0.1770
25	TGS2BAPSESN2$	8	1,716			0.2145
26	TGS2B-C-N-S	548	54,358	3	182,667	0.0992
27	TGS2B-CPP-N2S	1,182	198,871			0.1682
28	TGS2B-CPP-N-S	9,092	1,329,654	32	284,125	0.1462
29	TGS2B-CPP-P	3,437	528,651	14	245,500	0.1538
30	TGS2B-CPP-S	279,152	41,972,441	610	457,626	0.1504
31	TGS2B-CPP-S $	86	8,041			0.0935
32	TGS2B-CPP-T	239	24,597	1	239,000	0.1029
33	TGS2B-C-S	8,453	929,912	49	172,510	0.1100
34	TGS2B-C-S $	1,450	30,558	4	362,500	0.0211
35	TGS2B-DL-S #		148,636			
36	TGS2B-EDW	698	93,746	5	139,600	0.1343
37	TGS2B-N2-S	21,315	3,519,912			0.1651
38	TGS2B-N2-S @	775	60,192			0.0777
39	TGS2B-N2-S $	1,819	181,017			0.0995
40	TGS2B-N-P	105	16,813	1	105,000	0.1601
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

SALES OF ELECTRICITY BY RATE SCHEDULES

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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	TGS2B-N-S	98,598	15,618,496	745	132,346	0.1584
3	TGS2B-N-S @	1,615	114,970	8	201,875	0.0712
4	TGS2B-N-S $	3,414	352,285	39	87,538	0.1032
5	TGS2B-P	36,715	5,551,239	135	271,963	0.1512
6	TGS2B-P @	2,045	150,116	4	511,250	0.0734
7	TGS2B-P $	1,721	139,874	6	286,833	0.0813
8	TGS2B-S	9,590,943	1,537,113,788	59,365	161,559	0.1603
9	TGS2B-S @	1,507,253	112,414,020	5,549	271,626	0.0746
10	TGS2B-S $	367,997	34,414,442	2,485	148,087	0.0935
11	TGS2BS-APSE-S	249	45,947	2	124,500	0.1845
12	TGS2B-S-P	6,164	1,135,216	36	171,222	0.1842
13	TGS2B-S-P $	62	10,444	1	62,000	0.1685
14	TGS2B-S-S	4,729	664,584	14	337,786	0.1405
15	TGS2B-S-T	1,916	298,599	12	159,667	0.1558
16	TGS2B-S-T $	346	31,082	1	346,000	0.0898
17	TGS2B-T	7,143	700,190	23	310,565	0.0980
18	TGS2B-T @	28	3,282	1	28,000	0.1172
19	TGS2B-T $	17	1,325			0.0779
20	TGS2RAPSE-N2P	26	3,646			0.1402
21	TGS2RAPSE-N2S	2,000	284,200			0.1421
22	TGS2RAPSEN2S@	168	13,750			0.0818
23	TGS2RAPSEN2S$	152	23,405			0.1540
24	TGS2RAPSE-N-P	192	23,632	1	192,000	0.1231
25	TGS2RAPSE-N-S	17,267	2,436,307	155	111,400	0.1411
26	TGS2RAPSEN-S@	1,011	137,946	11	91,909	0.1364
27	TGS2RAPSEN-S$	1,725	169,163	16	107,813	0.0981
28	TGS2-R-APSE-S	388	83,179	9	43,111	0.2144
29	TGS2-R-N2-P	54	7,689			0.1424
30	TGS2-R-N2-S	8,273	1,215,009			0.1469
31	TGS2-R-N2-S @	443	41,326			0.0933
32	TGS2-R-N2-S $	904	105,396			0.1166
33	TGS2-R-N-P	831	131,634	3	277,000	0.1584
34	TGS2-R-N-S	75,396	11,039,279	617	122,198	0.1464
35	TGS2-R-N-S @	1,760	210,217	14	125,714	0.1194
36	TGS2-R-N-S $	8,594	874,380	60	143,233	0.1017
37	TGS2-R-S	1,895	332,678	28	67,679	0.1756
38	TGS2-R-S @	1,566	163,515	6	261,000	0.1044
39	TGS2-RTP-$	52	9,248	1	52,000	0.1778
40	TGS2-RTP-S	1,068	214,909	8	133,500	0.2012
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	TGS3-C-CPP-S	1,134	101,946	1	1,134,000	0.0899
3	TGS3-CPP-BIP-S	-43	-13,742			0.3196
4	TGS3-CPP-N2-S	9,270	1,320,780			0.1425
5	TGS3-CPP-N-P	2,317	306,002	3	772,333	0.1321
6	TGS3-CPP-N-S	36,609	5,004,325	47	778,915	0.1367
7	TGS3-CPP-P	42,709	6,285,579	44	970,659	0.1472
8	TGS3-CPP-S	1,675,339	252,343,364	1,761	951,357	0.1506
9	TGS3-CPP-S @	3,565	182,172	2	1,782,500	0.0511
10	TGS3-CPP-S $			1		
11	TGS3-CPP-T	5,922	729,771	5	1,184,400	0.1232
12	TGS3-RAPSEN2P	526	54,029			0.1027
13	TGS3RAPSEN2P$	56	4,192			0.0749
14	TGS3-RAPSEN2S	5,837	767,722			0.1315
15	TGS3RAPSEN2S@	253	24,369			0.0963
16	TGS3RAPSEN2S$	70	7,052			0.1007
17	TGS3RAPSE-N-P	4,746	519,295	7	678,000	0.1094
18	TGS3RAPSEN-P$	782	48,155	1	782,000	0.0616
19	TGS3RAPSE-N-S	24,231	3,208,794	80	302,888	0.1324
20	TGS3RAPSEN-S@	1,261	175,865	8	157,625	0.1395
21	TGS3RAPSEN-S$	429	38,219	1	429,000	0.0891
22	TGS3-R-APSE-S	242	63,359	3	80,667	0.2618
23	TGS3-R-BIPN-S	1,171	97,477	2	585,500	0.0832
24	TGS3-R-N2-P	771	89,688			0.1163
25	TGS3-R-N2-P @	71	6,645			0.0936
26	TGS3-R-N2P $	106	5,329			0.0503
27	TGS3-R-N2-S	14,483	1,954,050			0.1349
28	TGS3-R-N2-S @	8,689	692,470			0.0797
29	TGS3-R-N2S $	861	93,282			0.1083
30	TGS3-R-N-P	9,193	1,124,335	12	766,083	0.1223
31	TGS3-R-N-P @	569	55,282	1	569,000	0.0972
32	TGS3-R-N-P $	1,317	71,028	1	1,317,000	0.0539
33	TGS3-R-N-S	123,092	17,267,049	265	464,498	0.1403
34	TGS3-R-N-S @	82,694	6,673,415	76	1,088,079	0.0807
35	TGS3-R-N-S $	6,534	652,050	17	384,353	0.0998
36	TGS3-R-P	273	20,717	1	273,000	0.0759
37	TGS3-R-S	4,189	605,822	9	465,444	0.1446
38	TGS3-R-S @	4,148	353,555	3	1,382,667	0.0852
39	TGS3-R-S $	163	26,682	1	163,000	0.1637
40	TGS3RTP-BIP-S	4,374	736,490	5	874,800	0.1684
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	TGS3-RTP-P	364	106,811	1	364,000	0.2934
3	TGS3-RTP-S	2,721	522,057	4	680,250	0.1919
4	TOU8-BIP-S $	17,259	744,685	3	5,753,000	0.0431
5	TOU8-CPP-N2-S	-372	-61,658			0.1657
6	TOU8-CPP-N-P	28,630	3,627,251	6	4,771,667	0.1267
7	TOU8-CPP-N-S	32,445	4,230,210	14	2,317,500	0.1304
8	TOU8-CPP-N-T	43,993	4,055,638	1	43,993,000	0.0922
9	TOU8-CPP-P	482,292	60,778,058	98	4,921,347	0.1260
10	TOU8-CPP-P-N2	1,132	191,325			0.1690
11	TOU8-CPP-S	1,160,847	166,639,991	440	2,638,289	0.1436
12	TOU8-CPP-S @	325	21,239			0.0654
13	TOU8-CPP-S $	496	32,269			0.0651
14	TOU8-CPP-S-N2	12,414	1,767,704			0.1424
15	TOU8-CPP-T	88,286	9,636,724	11	8,026,000	0.1092
16	TOU-8-DL-S #		6,949,333			
17	TOU8-N-P $	44,090	2,542,142	2	22,045,000	0.0577
18	TOU8-N-S $	5,705	398,406	2	2,852,500	0.0698
19	TOU8-N-T $	8,376	386,351	1	8,376,000	0.0461
20	TOU8-P $	64,356	4,140,704	10	6,435,600	0.0643
21	TOU8R-APSE-S	990	200,020	3	330,000	0.2020
22	TOU8R-BIP-N-S	3,267	357,678	2	1,633,500	0.1095
23	TOU8-R-BIP-P	8,223	974,138	1	8,223,000	0.1185
24	TOU8-R-N2-P	7,721	950,134			0.1231
25	TOU8-R-N2-P @	1,934	130,670			0.0676
26	TOU8-R-N2-P $	196	17,633			0.0900
27	TOU8-R-N2-S	7,732	1,007,670			0.1303
28	TOU8-R-N2-S @	3,980	312,801			0.0786
29	TOU8-R-N2-S $	678	63,070			0.0930
30	TOU8-R-N-P	91,928	11,215,655	36	2,553,556	0.1220
31	TOU8-R-N-P @	33,681	2,427,588	7	4,811,571	0.0721
32	TOU8-R-N-P $	6,112	457,054	3	2,037,333	0.0748
33	TOU8-R-N-S	91,392	12,034,194	47	1,944,511	0.1317
34	TOU8-R-N-S @	47,526	3,901,832	23	2,066,348	0.0821
35	TOU8-R-N-S $	6,930	699,036	5	1,386,000	0.1009
36	TOU8-R-N-T	16,520	1,446,469	1	16,520,000	0.0876
37	TOU8-R-P	3,516	455,989	1	3,516,000	0.1297
38	TOU8-R-P @	16,072	1,171,493	2	8,036,000	0.0729
39	TOU8-R-S	416	92,089	1	416,000	0.2214
40	TOU8-R-S @	20,150	1,524,721	8	2,518,750	0.0757
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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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	TOU8-S $	104,798	7,643,593	34	3,082,294	0.0729
3	TOU8-T $	13,208	502,708	1	13,208,000	0.0381
4	TOU-EV-4 N2		-253			
5	TOU-EV-4-S	12,256	3,206,560	151	81,166	0.2616
6	TOU-EV-4-S @	153	20,639	3	51,000	0.1349
7	TOU-EV-4-S N2	90	4,980			0.0553
8	TOU-EV-6-P $	1,180	214,889	1	1,180,000	0.1821
9	TOU-EV-6-S	23,813	4,164,906	15	1,587,533	0.1749
10	TOUG3A-APSE-P	2,489	432,892	4	622,250	0.1739
11	TOUG3AAPSE-P@	1,432	110,439	1	1,432,000	0.0771
12	TOUG3A-APSE-S	152,061	29,812,726	339	448,558	0.1961
13	TOUG3AAPSE-S@	20,197	2,421,866	46	439,065	0.1199
14	TOUG3A-APSES$	8,482	869,140	16	530,125	0.1025
15	TOUG3B-APSE-P	7,500	1,042,115	7	1,071,429	0.1389
16	TOUG3B-APSE-S	120,098	20,002,427	160	750,613	0.1666
17	TOUG3BAPSE-S@	16,648	1,428,861	18	924,889	0.0858
18	TOUG3B-APSES$	6,434	583,184	9	714,889	0.0906
19	TOU-GS3-A-P	9,660	1,620,434	11	878,182	0.1677
20	TOU-GS3-A-P @	1,695	119,424	1	1,695,000	0.0705
21	TOU-GS3-A-P $	499	52,034	1	499,000	0.1043
22	TOU-GS3-A-P-N	170	39,300	1	170,000	0.2312
23	TOU-GS3-A-PN2	16	3,200			0.2000
24	TOU-GS-3-A-S	437,780	79,349,489	675	648,563	0.1813
25	TOU-GS3-A-S @	26,504	2,646,070	35	757,257	0.0998
26	TOU-GS3-A-S $	13,429	1,560,389	25	537,160	0.1162
27	TOUGS3AS-BIP	8,779	1,339,703	10	877,900	0.1526
28	TOUGS3AS-BIP @	2,122	112,957	1	2,122,000	0.0532
29	TOU-GS3-A-S-N	15,752	2,648,321	50	315,040	0.1681
30	TOUGS3-A-S-N@			1		
31	TOU-GS3-A-SN2	8,189	1,547,450			0.1890
32	TOU-GS3-A-SN2@	1,813	103,767			0.0572
33	TOU-GS3A-S-P	-28	-16,332			0.5833
34	TOU-GS3A-S-S	476	60,879	1	476,000	0.1279
35	TOU-GS3B-C-P	1,042	105,304	1	1,042,000	0.1011
36	TOU-GS3B-C-S	5,022	467,990	4	1,255,500	0.0932
37	TOU-GS3B-C-S$	494	9,827			0.0199
38	TOU-GS3BC-S-N	755	78,021	1	755,000	0.1033
39	TOU-GS3B-EDW	607	74,544	1	607,000	0.1228
40	TOU-GS3-B-P	64,920	8,845,235	51	1,272,941	0.1362
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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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	TOU-GS3-B-P @	14,721	1,182,648	12	1,226,750	0.0803
2	TOU-GS3-B-P $	6,169	470,744	5	1,233,800	0.0763
3	TOUGS3BP-BIP	11,371	1,491,444	7	1,624,429	0.1312
4	TOUGS3B-PBIP$	578	37,930			0.0656
5	TOUGS3BP-CPP	-73	-12,725			0.1743
6	TOU-GS3-B-P-N	3,723	503,110	4	930,750	0.1351
7	TOU-GS3B-P-N$	4,739	374,162	3	1,579,667	0.0790
8	TOU-GS3-B-PN2	54	8,814			0.1632
9	TOU-GS3B-PN2$	420	41,420			0.0986
10	TOU-GS-3-B-S	2,816,792	388,252,172	2,356	1,195,582	0.1378
11	TOU-GS3-B-S @	1,651,190	106,439,832	1,118	1,476,914	0.0645
12	TOU-GS3-B-S $	140,581	10,810,020	126	1,115,722	0.0769
13	TOUGS3BS-BIP	117,673	13,720,165	76	1,548,329	0.1166
14	TOUGS3BS-BIP@	52,669	3,317,369	39	1,350,487	0.0630
15	TOUGS3B-SBIP$	4,306	245,068	3	1,435,333	0.0569
16	TOUGS3BS-CPP	-2,054	-265,592			0.1293
17	TOUGS3BS-CPP@	283	21,504			0.0760
18	TOU-GS3-B-S-N	62,664	8,780,036	75	835,520	0.1401
19	TOUGS3-B-S-N@	27,641	1,988,925	23	1,201,783	0.0720
20	TOU-GS3B-S-N$	2,277	207,184	6	379,500	0.0910
21	TOU-GS3-B-SN2	14,164	2,088,264			0.1474
22	TOUGS3-B-SN2@	3,501	267,477			0.0764
23	TOUGS3-B-SN2$	1,266	134,756			0.1064
24	TOU-GS3B-S-P	3,944	604,020	4	986,000	0.1531
25	TOU-GS3B-S-S	21,327	2,633,647	16	1,332,938	0.1235
26	TOU-GS3B-S-S@	4,933	286,410	3	1,644,333	0.0581
27	TOU-GS3B-S-S$	719	53,145	1	719,000	0.0739
28	TOU-GS3B-S-T	4,701	1,100,373	11	427,364	0.2341
29	TOU-GS3-B-T	3,117	310,680	3	1,039,000	0.0997
30	TOU-GS3-B-T @	2,898	126,249	2	1,449,000	0.0436
31	TOU-GS3-B-T $	240	32,672			0.1361
32	TOU-GS3SOP-S	3,074	594,889	5	614,800	0.1935
33	TOU-GS3SOP-S$	347	32,260			0.0930
34	TOU-PA-ICE	1,035	122,932	2	517,500	0.1188
35	TOUPA-ICE-API	-388	-34,865	1	-388,000	0.0899
36	TPA2-A	326,609	52,991,725	6,015	54,299	0.1622
37	TPA2-A @	1,106	64,975	7	158,000	0.0587
38	TPA2-A $	11,847	1,074,606	104	113,913	0.0907
39	TPA2-A-API	40,433	3,835,319	308	131,276	0.0949
40	TPA2-A-API $	264	29,508	3	88,000	0.1118
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	TPA2-A-API-N	4,122	338,719	12	343,500	0.0822
3	TPA2-A-API-N$	372	31,559	2	186,000	0.0848
4	TPA2-A-API-N2	3,049	169,931			0.0557
5	TPA2-A-N	10,646	1,002,565	38	280,158	0.0942
6	TPA2-A-N $	418	31,302	2	209,000	0.0749
7	TPA2-A-N2	7,023	594,399			0.0846
8	TPA2-A-N2 $	29	1,857			0.0640
9	TPA2-A-P	18	-22,247	1	18,000	-1.2359
10	TPA2-A-P $	9	1,323			0.1470
11	TPA2-A-S-API@	1	232			0.2320
12	TPA2-B	1,176,976	157,946,464	14,862	79,194	0.1342
13	TPA2-B @	33,987	1,882,297	178	190,938	0.0554
14	TPA2-B $	41,029	2,773,189	489	83,904	0.0676
15	TPA2-B-API	107,096	11,194,031	491	218,118	0.1045
16	TPA2-B-API @			4		
17	TPA2-B-API $	590	24,273			0.0411
18	TPA2-B-API-N		-321	2		
19	TPA2-B-CPP	6,107	758,529	15	407,133	0.1242
20	TPA2-B-DL #		620			
21	TPA2-B-N		17,425			
22	TPA2-B-N $		103			
23	TPA2-B-P	10,678	1,131,092	33	323,576	0.1059
24	TPA2-B-P $	904	42,187	2	452,000	0.0467
25	TPA2-B-P-API	1,212	101,536	2	606,000	0.0838
26	TPA2-B-S	554	50,618	3	184,667	0.0914
27	TPA2B-S-API-N	886	82,957			0.0936
28	TPA2B-S-APIN2	367	33,956			0.0925
29	TPA2-B-S-N	6,348	616,033	58	109,448	0.0970
30	TPA2-B-S-N $	515	37,613	8	64,375	0.0730
31	TPA2-B-S-N2	2,124	206,196			0.0971
32	TPA2-RTP	1,722	232,207	10	172,200	0.1348
33	TPA2-SOP1	58,499	7,833,980	462	126,621	0.1339
34	TPA2-SOP1 $	4,383	326,207	25	175,320	0.0744
35	TPA2-SOP1-API		-1,060			
36	TPA2-SOP1APIS	16,021	1,784,596	90	178,011	0.1114
37	TPA2SOP1APIS$	376	31,817	3	125,333	0.0846
38	TPA2-SOP1-N		-486			
39	TPA2-SOP1-P	344	43,931	1	344,000	0.1277
40	TPA2-SOP1-S @	778	50,314	3	259,333	0.0647
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	TPA2-SOP1-S-N	1,244	106,727	7	177,714	0.0858
3	TPA2-SOP1-SN2	146	10,573			0.0724
4	TPA2-SOP2	26,942	3,430,164	147	183,279	0.1273
5	TPA2-SOP2 @	21	3,412	1	21,000	0.1625
6	TPA2-SOP2 $	3,413	169,524	11	310,273	0.0497
7	TPA2-SOP2-API	9,335	1,049,063	39	239,359	0.1124
8	TPA2SP1AISN2	70	15,064			0.2152
9	TPA3-A		-26,343			
10	TPA3-A $	5,233	414,165	9	581,444	0.0791
11	TPA3-A-API		-8,450			
12	TPA3-A-API-N	5,417	288,448	1	5,417,000	0.0532
13	TPA3-AAPI-SN2	191	29,122			0.1525
14	TPA3-A-N		-196,756			
15	TPA3-A-N2		3,851			
16	TPA3-A-NEM $		-92			
17	TPA3-A-P	4,618	556,292	5	923,600	0.1205
18	TPA3-A-P @	229	29,091	1	229,000	0.1270
19	TPA3-A-P-API	576	76,040	1	576,000	0.1320
20	TPA3-A-P-N	4,871	433,343	3	1,623,667	0.0890
21	TPA3-A-P-N $	1,033	55,617	1	1,033,000	0.0538
22	TPA3-A-P-N2	1,011	93,681			0.0927
23	TPA3-A-S	185,783	23,695,567	346	536,945	0.1275
24	TPA3-A-S @	1,913	124,682	2	956,500	0.0652
25	TPA3-A-S-API	28,705	2,147,664	46	624,022	0.0748
26	TPA3-A-S-API@	3,807	98,583	2	1,903,500	0.0259
27	TPA3-A-S-N	41,141	3,839,082	28	1,469,321	0.0933
28	TPA3-A-S-N $	89	4,568			0.0513
29	TPA3-A-S-N2	7,376	732,555			0.0993
30	TPA3-A-S-N2 $	198	13,988			0.0706
31	TPA3-B	467,524	50,588,017	461	1,014,152	0.1082
32	TPA3-B @	26,987	1,534,809	19	1,420,368	0.0569
33	TPA3-B $	12,504	687,620	13	961,846	0.0550
34	TPA3-B-API	59,520	5,203,966	47	1,266,383	0.0874
35	TPA3-B-API @	10	1,280			0.1280
36	TPA3-B-API $	192	9,794			0.0510
37	TPA3B-API-N1S	305	15,371			0.0504
38	TPA3-B-API-NEM		8			
39	TPA3-B-API-P	4,271	278,196	1	4,271,000	0.0651
40	TPA3-B-API-S	34,352	2,797,084	32	1,073,500	0.0814
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
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1	ACCOUNT 442 CONTINUED					
2	TPA3-B-API-S$	1,675	71,258	1	1,675,000	0.0425
3	TPA3-B-BIP	-197	-17,479			0.0887
4	TPA3-B-CPP	-7,885	-460,616	18	-438,056	0.0584
5	TPA3-B-CPP-P	36,803	3,337,667			0.0907
6	TPA3-B-CPP-S	14,818	1,586,575	12	1,234,833	0.1071
7	TPA3-B-DL #		174,184			
8	TPA3-B-N2	795	87,859			0.1105
9	TPA3-B-N2-S $	825	33,845			0.0410
10	TPA3-B-NEM	3,979	385,422	6	663,167	0.0969
11	TPA3-B-NEM $	322	28,487	1	322,000	0.0885
12	TPA3-B-NEM-P	2,027	184,518			0.0910
13	TPA3-B-NEM-S	2,791	273,769	2	1,395,500	0.0981
14	TPA3-B-NEM-S$	326	30,129	1	326,000	0.0924
15	TPA3-B-P	-18,034	-1,426,747	11	-1,639,455	0.0791
16	TPA3-B-P @	5,650	223,185	1	5,650,000	0.0395
17	TPA3-B-P $	532	25,593			0.0481
18	TPA3-B-P-N2	2,727	364,865			0.1338
19	TPA3-B-S	50,966	4,618,820	2	25,483,000	0.0906
20	TPA3-B-S @	12,133	693,905	13	933,308	0.0572
21	TPA3-B-S $	22,372	1,179,052	24	932,167	0.0527
22	TPA3-BSAPIN2	407	26,808			0.0659
23	TPA3-B-SEC	291,618	31,823,675	293	995,283	0.1091
24	TPA3-B-S-N2	699	78,930			0.1129
25	TPA3-B-T	10,429	830,230			0.0796
26	TPA3-RTP	1,635	201,717	3	545,000	0.1234
27	TPA3-SOP1	49,400	5,754,265	74	667,568	0.1165
28	TPA3-SOP1 @	2,328	170,223	3	776,000	0.0731
29	TPA3-SOP1 $	2,016	143,601	3	672,000	0.0712
30	TPA3-SOP1-API	7,168	774,235	10	716,800	0.1080
31	TPA3-SOP1API@	17	4,326			0.2545
32	TPA3-SOP1API$	97	6,664			0.0687
33	TPA3-SOP1APIP	605	50,580			0.0836
34	TPA3SOP1APIP$	403	25,067			0.0622
35	TPA3-SOP1APIS	3,299	334,934	5	659,800	0.1015
36	TPA3SOP1API@	167	22,857			0.1369
37	TPA3SOP1API$	157	15,940			0.1015
38	TPA3-SOP1 N2	17	4,217			0.2481
39	TPA3-SOP1-P	2,043	201,575	1	2,043,000	0.0987
40	TPA3-SOP1-P @	923	43,700			0.0473
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	ACCOUNT 442 CONTINUED					
2	TPA3-SOP1-P $	414	23,467			0.0567
3	TPA3-SOP1-S $	1,262	122,000	2	631,000	0.0967
4	TPA3-SOP2	42,285	5,018,211	64	660,703	0.1187
5	TPA3-SOP2 @	1,658	127,022	3	552,667	0.0766
6	TPA3-SOP2 $	731	68,542	2	365,500	0.0938
7	TPA3-SOP2-API	6,041	618,599	9	671,222	0.1024
8	TPA3-SOP2API$	354	21,555	1	354,000	0.0609
9	TPA3-SOP2-N	547	58,096	1	547,000	0.1062
10	TU8A-N-S	1,853	268,371	1	1,853,000	0.1448
11	TU8A-P	11,010	1,886,237	3	3,670,000	0.1713
12	TU8A-S	6,949	1,110,260	4	1,737,250	0.1598
13	TU8A-T	42,291	4,906,328	7	6,041,571	0.1160
14	TU8BAPSECPP-P	16,881	2,780,358	7	2,411,571	0.1647
15	TU8BAPSECPP-S	23,798	3,780,996	14	1,699,857	0.1589
16	TU8B-APSE-N2P	1,897	313,225			0.1651
17	TU8B-APSE-N2S	1,795	313,484			0.1746
18	TU8B-APSE-N2T	8,799	735,404			0.0836
19	TU8B-APSE-N-P	372	65,871	2	186,000	0.1771
20	TU8B-APSE-N-S	6,841	1,025,265	7	977,286	0.1499
21	TU8B-APSE-N-T	105,607	9,707,044	1	105,607,000	0.0919
22	TU8B-APSE-P	40,034	6,150,383	15	2,668,933	0.1536
23	TU8B-APSE-P @	39,426	2,814,525	13	3,032,769	0.0714
24	TU8B-APSE-P $	623	63,248	1	623,000	0.1015
25	TU8B-APSE-S	110,670	17,435,113	55	2,012,182	0.1575
26	TU8B-APSE-S @	23,035	1,963,333	12	1,919,583	0.0852
27	TU8B-APSE-S $	1,534	171,216	1	1,534,000	0.1116
28	TU8B-APSE-SN$	598	53,473			0.0894
29	TU8B-APSESN2@	357	53,859			0.1509
30	TU8B-APSE-T	35,735	2,945,836	1	35,735,000	0.0824
31	TU8B-APSE-T @	99,480	2,792,156	1	99,480,000	0.0281
32	TU8B-CPP-P	-2,948	-366,670			0.1244
33	TU8B-CPP-S	-1,217	-152,690			0.1255
34	TU8-BIPN2-S $		-2,384			
35	TU8B-P	1,724,428	202,148,051	228	7,563,281	0.1172
36	TU8B-P @	1,445,937	81,911,549	124	11,660,782	0.0566
37	TU8B-P-BIP	579,470	58,944,795	51	11,362,157	0.1017
38	TU8B-P-BIP @	324,019	14,148,716	22	14,728,136	0.0437
39	TU8B-P-BIP-N	28,208	3,042,970	2	14,104,000	0.1079
40	TU8B-P-BIP-N@	21,066	1,011,223	1	21,066,000	0.0480
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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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	TU8B-P-BIP-N2	2,713	269,621			0.0994
3	TU8B-P-N	274,326	31,738,957	24	11,430,250	0.1157
4	TU8B-P-N @	7,615	515,992	2	3,807,500	0.0678
5	TU8B-P-N2	35,008	3,973,565			0.1135
6	TU8B-P-N2 @	458	31,306			0.0684
7	TU8B-S	3,382,256	439,991,691	1,002	3,375,505	0.1301
8	TU8B-S @	1,707,289	109,478,750	423	4,036,144	0.0641
9	TU8B-S-BIP	669,040	74,727,444	120	5,575,333	0.1117
10	TU8B-S-BIP @	265,889	14,078,028	50	5,317,780	0.0529
11	TU8B-S-BIP-N	12,646	1,415,896	2	6,323,000	0.1120
12	TU8B-S-BIP-N@	20,476	1,081,595	3	6,825,333	0.0528
13	TU8B-S-BIP-N$	1,586	84,082			0.0530
14	TU8B-S-BIP-N2	2,589	231,807			0.0895
15	TU8B-S-N	145,107	18,724,438	49	2,961,367	0.1290
16	TU8B-S-N @	128,006	8,206,180	47	2,723,532	0.0641
17	TU8B-S-N2	31,945	4,118,992			0.1289
18	TU8B-S-N2 @	26,547	1,813,658			0.0683
19	TU8B-T	1,046,334	87,588,161	25	41,853,360	0.0837
20	TU8B-T @	1,369,705	42,103,357	28	48,918,036	0.0307
21	TU8B-T-BIP	1,194,818	80,272,179	22	54,309,909	0.0672
22	TU8B-T-BIP @	1,173,773	15,913,853	10	117,377,300	0.0136
23	TU8B-T-BIP-N	156,417	12,218,346	2	78,208,500	0.0781
24	TU8B-T-BIP-N2	9,843	767,856			0.0780
25	TU8B-T-N	255,649	20,747,147	7	36,521,286	0.0812
26	TU8B-T-N2	12,002	783,555			0.0653
27	TU8-N2-P $	4,670	247,106			0.0529
28	TU8-N2-S $	278	26,587			0.0956
29	TU8-N2-T $	701	30,655			0.0437
30	TU8R-APSE-N2P	1,744	245,968			0.1410
31	TU8RAPSE-N2P@	384	30,575			0.0796
32	TU8RAPSEN2-P$	108	10,455			0.0968
33	TU8R-APSE-N2S	2,821	344,388			0.1221
34	TU8RAPSE-N2S@	257	27,308			0.1063
35	TU8RAPSEN2-S$	415	36,165			0.0871
36	TU8R-APSE-N-P	7,471	854,503	6	1,245,167	0.1144
37	TU8RAPSE-N-P@	3,312	285,497	2	1,656,000	0.0862
38	TU8RAPSEN-P $	4,551	352,822	3	1,517,000	0.0775
39	TU8R-APSE-N-S	21,780	2,922,777	22	990,000	0.1342
40	TU8RAPSE-N-S@	1,072	112,238	1	1,072,000	0.1047
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 442 CONTINUED					
2	TU8RAPSEN-S $	2,984	246,544	3	994,667	0.0826
3	TUG3AAPSE-N2S	3,431	631,205			0.1840
4	TUG3AAPSEN2S$	46	6,617			0.1438
5	TUG3AAPSE-N-S	4,068	709,617	22	184,909	0.1744
6	TUG3BAPSECPPS	20,703	3,725,185	34	608,912	0.1799
7	TUG3BAPSE-N2S	1,560	310,860			0.1993
8	TUG3BAPSEN2S@	470	48,445			0.1031
9	TUG3BAPSE-N-S	3,436	553,512	10	343,600	0.1611
10	TUG3BAPSEN-S@	831	66,528	2	415,500	0.0801
11	TUG3BAPSE-S-S	1,123	177,484	1	1,123,000	0.1580
12	TUGS3-B-S-DL#		76,645			
13	WIRETECHRATE	6,397	1,074,607			0.1680
14						
15	OTHER ADJUSTMENTS	-16	-1,722,981			107.6863
16						
17	TOTAL ACCOUNT 442	54,636,444	6,567,441,653	631,042	86,581	0.1202
18						
19						
20	ACCOUNT 444					
21						
22	AL-2	342	27,659	25	13,680	0.0809
23	AL-2 $	173	3,127	1	173,000	0.0181
24	GS-1		315	1		
25	LS-1-ALLNITE	255,358	70,631,824	3,809	67,041	0.2766
26	LS1-ALLNITE@	3,008	624,626	10	300,800	0.2077
27	LS1-ALLNITE$	36,136	7,124,082	186	194,280	0.1971
28	LS-2	79,124	7,832,547	3,796	20,844	0.0990
29	LS-2 @	2,309	282,771	66	34,985	0.1225
30	LS-2 $	5,468	224,212	221	24,742	0.0410
31	LS-2-B	21,544	3,492,902	37	582,270	0.1621
32	LS-2-B $	1	51	1	1,000	0.0510
33	LS-3	4,380	392,263	613	7,145	0.0896
34	LS-3 @	218	14,004	29	7,517	0.0642
35	LS-3 $	494	14,061	39	12,667	0.0285
36	LS-3-B	38,534	3,264,705	5,063	7,611	0.0847
37	LS-3-B @	4,328	174,759	612	7,072	0.0404
38	LS-3-B $	767	37,144	162	4,735	0.0484
39	OL-1-ALLNITE	3	403	1	3,000	0.1343
40	TC-1	7,082	1,289,263	1,924	3,681	0.1820
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 444 CONTINUED					
2	TC-1 @	81	9,038	19	4,263	0.1116
3	TC-1 $	338	46,692	126	2,683	0.1381
4	TGS1-A	1,673	337,518	360	4,647	0.2017
5	TGS1-A @	4	492	1	4,000	0.1230
6	TGS1-A $	66	8,483	14	4,714	0.1285
7	TGS1-A-N	9	1,507	1	9,000	0.1674
8	TGS1-B	325	42,544	30	10,833	0.1309
9	TGS1-B @	7	792	2	3,500	0.1131
10	TGS2A-S	61	18,184	2	30,500	0.2981
11	TGS2B-S	1,399	192,027	7	199,857	0.1373
12	TU8B-P	32,473	3,358,060	1	32,473,000	0.1034
13						
14	OTHER ADJUSTMENTS		16,961			
15						
16	TOTAL ACCOUNT 444	495,705	99,463,016	17,159	28,889	0.2006
17						
18	ACCOUNT 445					
19						
20	EDWARDS-AFB	149,855	7,171,500	3	49,951,667	0.0479
21	MARCH-AFB	41,328	1,819,592	1	41,328,000	0.0440
22						
23	OTHER ADJUSTMENTS		-23,382			
24						
25	TOTAL ACCOUNT 445	191,183	8,967,710	4	47,795,750	0.0469
26						
27	ACCOUNT 446					
28						
29	LS-3	22	1,927	3	7,333	0.0876
30	LS-3-B	5	608	3	1,667	0.1216
31	TC-1	74	12,765	16	4,625	0.1725
32	TC-1 @	9	810	1	9,000	0.0900
33	TC-1 $	1	161	1	1,000	0.1610
34	TGS1-A	213	40,887	36	5,917	0.1920
35	TGS1-A @	10	972	2	5,000	0.0972
36	TGS1-A $	78	6,766	5	15,600	0.0867
37	TGS1-B	78	11,545	9	8,667	0.1480
38	TGS1-B @	57	3,959	8	7,125	0.0695
39	TGS2A-S	142	17,621	1	142,000	0.1241
40	TGS2B-P	187	35,137	1	187,000	0.1879
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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1	ACCOUNT 446 CONTINUED					
2	TGS2B-P $	106	13,229	1	106,000	0.1248
3	TGS2B-S	544	72,009	3	181,333	0.1324
4	TGS2B-S $	21	3,895	1	21,000	0.1855
5	TGS3-CPP-P	17,409	2,830,128	15	1,160,600	0.1626
6	TGS3-CPP-S	1,329	143,562	1	1,329,000	0.1080
7	TOU8-CPP-P	38,151	5,332,803	15	2,543,400	0.1398
8	TOU8-CPP-P $	356	34,802			0.0978
9	TOU-P $	6,324	621,298	4	1,581,000	0.0982
10	TOU-GS3-A-P	3,023	529,348	4	755,750	0.1751
11	TOU-GS3-B-P	550	129,194			0.2349
12	TOU-GS3-B-P $	2,003	197,206	2	1,001,500	0.0985
13	TOU-GS-3-B-S	179	23,418			0.1308
14	TOU-GS3-B-S $	501	26,437			0.0528
15	TU8B-P	9,475	1,211,502	2	4,737,500	0.1279
16	TU8B-P @	4,680	230,095	1	4,680,000	0.0492
17						
18	OTHER ADJUSTMENTS	1				
19						
20	TOTAL ACCOUNT 446	85,528	11,532,084	135	633,541	0.1348
21						
22						
23						
24	ACCOUNT 448					
25						
26	GS-1-SCE	26	5,189	5	5,200	0.1996
27	GS-2-SCE	152	33,132	1	152,000	0.2180
28	PA-1-SCE	-524	-58,895	11	-47,636	0.1124
29	PA-2-SCE	1,033	125,237	6	172,167	0.1212
30	TOU-GS3B-SCE	1,000	110,480	1	1,000,000	0.1105
31						
32	OTHER ADJUSTMENTS	1	-16			-0.0160
33						
34	TOTAL ACCOUNT 448	1,688	215,127	24	70,333	0.1274
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	85,275,717	11,579,572,495	5,111,896	16,682	0.1358
42	Total Unbilled Rev.(See Instr. 6)	1,575,869	269,721,000	0	0	0.1712
43	TOTAL	86,851,586	11,849,293,495	5,111,896	16,990	0.1364

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

This footnote applies to entire schedule:
"@" Symbol represents Direct Access Rate Schedule;
"$" Symbol represents Community Choice Aggregation Rate Schedule.

2017 FERC Form 1 - Page 304 FOOTNOTE Legend & Instruction #5 Data

FOOTNOTES:

A = Southern California Edison Company revenue only. Does not reflect Department of Water Resources (DWR) portion that is billed and remitted to DWR. Thus, the Revenue per KWh may not reflect the customers' full rate.
B = Data reflected under parent rate schedule or other applicable tariff.
C = Less than 1 MWh.
D = Less than 12 months' data.

OTHER ADJUSTMENTS

OTHER ADJUSTMENTS may include Misc Transactions Used for Billing Purposes, rounding, and/or other miscellaneous adjustments.

FOR INSTRUCTION 5:

ESTIMATED REVENUE DERIVED FROM FUEL COST ADJUSTMENT

440	RESIDENTIAL SALES	$0
442	AGRICULTURAL, COMMERCIAL & INDUSTRIAL SALES	$0
444	PUBLIC STREET & HIGHWAY LIGHTING	$0
445	OTHER SALES TO PUBLIC AUTHORITIES	$0
446	RAILROADS	$0
448	INTERDEPARTMENTAL	$0
	TOTAL SALES TO ULTIMATE CONSUMERS	$0
447	SALES FOR RESALE & FRINGE	$0
	TOTAL SALES	$0

Schedule Page: 304 Line No.: 32 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304 Line No.: 32 Column: d

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.1 Line No.: 24 Column: b

C = Less than 1 MWh.

Schedule Page: 304.1 Line No.: 24 Column: c

D = Less than 12 months' data.

Schedule Page: 304.1 Line No.: 24 Column: f

D = Less than 12 months' data.

Schedule Page: 304.1 Line No.: 31 Column: d

D = Less than 12 months' data.

Schedule Page: 304.1 Line No.: 35 Column: d
D = Less than 12 months' data.
Schedule Page: 304.1 Line No.: 37 Column: d
D = Less than 12 months' data.
Schedule Page: 304.3 Line No.: 39 Column: b
C = Less than 1 MWh.
Schedule Page: 304.3 Line No.: 39 Column: c
D = Less than 12 months' data.
Schedule Page: 304.3 Line No.: 39 Column: f
D = Less than 12 months' data.
Schedule Page: 304.4 Line No.: 22 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 22 Column: d
D = Less than 12 months' data.
Schedule Page: 304.4 Line No.: 23 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 23 Column: d
D = Less than 12 months' data.
Schedule Page: 304.4 Line No.: 26 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 27 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 28 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 31 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 32 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 34 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 35 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 37 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 39 Column: b
C = Less than 1 MWh.
Schedule Page: 304.4 Line No.: 40 Column: b
C = Less than 1 MWh.
Schedule Page: 304.5 Line No.: 20 Column: b
C = Less than 1 MWh.
Schedule Page: 304.5 Line No.: 20 Column: c
D = Less than 12 months' data.
Schedule Page: 304.7 Line No.: 30 Column: b
C = Less than 1 MWh.
Schedule Page: 304.7 Line No.: 31 Column: b
C = Less than 1 MWh.
Schedule Page: 304.7 Line No.: 32 Column: b
C = Less than 1 MWh.
Schedule Page: 304.7 Line No.: 33 Column: b
C = Less than 1 MWh.
Schedule Page: 304.8 Line No.: 4 Column: b

C = Less than 1 MWh.

Schedule Page: 304.8 Line No.: 29 Column: b

C = Less than 1 MWh.

Schedule Page: 304.9 Line No.: 3 Column: b

C = Less than 1 MWh.

Schedule Page: 304.10 Line No.: 29 Column: b

C = Less than 1 MWh.

Schedule Page: 304.10 Line No.: 35 Column: a

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

Schedule Page: 304.11 Line No.: 6 Column: b

C = Less than 1 MWh.

Schedule Page: 304.11 Line No.: 7 Column: b

C = Less than 1 MWh.

Schedule Page: 304.11 Line No.: 16 Column: b

C = Less than 1 MWh.

Schedule Page: 304.11 Line No.: 26 Column: b

C = Less than 1 MWh.

Schedule Page: 304.12 Line No.: 8 Column: b

C = Less than 1 MWh.

Schedule Page: 304.12 Line No.: 12 Column: b

C = Less than 1 MWh.

Schedule Page: 304.12 Line No.: 21 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.12 Line No.: 21 Column: d

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.12 Line No.: 22 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.12 Line No.: 22 Column: d

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.12 Line No.: 26 Column: b

C = Less than 1 MWh.

Schedule Page: 304.13 Line No.: 16 Column: b

C = Less than 1 MWh.

Schedule Page: 304.13 Line No.: 34 Column: b

C = Less than 1 MWh.

Schedule Page: 304.13 Line No.: 35 Column: b

C = Less than 1 MWh.

Schedule Page: 304.14 Line No.: 7 Column: b

C = Less than 1 MWh.

Schedule Page: 304.14 Line No.: 40 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.14 Line No.: 40 Column: d

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.15 Line No.: 35 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.15 Line No.: 35 Column: d

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.17 Line No.: 10 Column: b

C = Less than 1 MWh.

Schedule Page: 304.18 Line No.: 16 Column: b

B = Data reflected under parent rate schedule or other applicable tariff.

Schedule Page: 304.18 Line No.: 16 Column: d
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.19 Line No.: 4 Column: b
C = Less than 1 MWh.
Schedule Page: 304.19 Line No.: 30 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 16 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 18 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 20 Column: b
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.21 Line No.: 20 Column: d
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.21 Line No.: 21 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 22 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 35 Column: b
C = Less than 1 MWh.
Schedule Page: 304.21 Line No.: 38 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 9 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 11 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 14 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 15 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 16 Column: b
C = Less than 1 MWh.
Schedule Page: 304.22 Line No.: 38 Column: b
C = Less than 1 MWh.
Schedule Page: 304.23 Line No.: 7 Column: b
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.23 Line No.: 7 Column: d
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.24 Line No.: 34 Column: b
C = Less than 1 MWh.
Schedule Page: 304.26 Line No.: 12 Column: b
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.26 Line No.: 12 Column: d
B = Data reflected under parent rate schedule or other applicable tariff.
Schedule Page: 304.26 Line No.: 15 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.
Schedule Page: 304.26 Line No.: 24 Column: b
C = Less than 1 MWh.
Schedule Page: 304.27 Line No.: 14 Column: a
Other adjustments may include Miscellaneous Transactions Used for Billing Purposes, Municipal Departing Load Settlements, rounding and other miscellaneous adjustments.

Schedule Page: 304.27 Line No.: 23 Column: a

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

Schedule Page: 304.28 Line No.: 18 Column: a

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

Schedule Page: 304.28 Line No.: 32 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	California Independent System Operator		1	N/A	N/A	N/A
2	Arizona Public Service Company	SF	WSPP-2	N/A	N/A	N/A
3	BP Energy Company	SF	FERC VOL. 8	N/A	N/A	N/A
4	Calpine Energy Services LP	SF	FERC VOL. 8	N/A	N/A	N/A
5	Clean Power Alliance Southern CA	OS		N/A	N/A	N/A
6	Direct Energy Business Marketing, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
7	EDF Trading North America, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
8	Exelon Generation Company, LLC	SF	FERC VOL. 8	N/A	N/A	N/A
9	Macquarie Energy LLC	SF	FERC VOL. 8	N/A	N/A	N/A
10	Marin Clean Energy	OS		N/A	N/A	N/A
11	NRG Power Marketing LLC	LU	FERC VOL. 8	N/A	N/A	N/A
12	PacifiCorp	SF	FERC VOL. 8	N/A	N/A	N/A
13	Public Service Company of New Mexico	SF	WSPP-2	N/A	N/A	N/A
14	RIO BRAVO FRESNO	OS		N/A	N/A	N/A
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	RIO BRAVO ROCKLIN	OS		N/A	N/A	N/A
2	Sacramento Municipal Utility District	SF	WSPP-2	N/A	N/A	N/A
3	Salt River Project Agricultural Improv	SF	WSPP-2	N/A	N/A	N/A
4	Shell Energy North America (US), L.P.	SF	FERC VOL. 8	N/A	N/A	N/A
5	Sonoma Clean Power Authority	SF		N/A	N/A	N/A
6	Tucson Electric Power Company	LU	WSPP-2	N/A	N/A	N/A
7	Tullett Prebon Americas Corp.	OS		N/A	N/A	N/A
8						
9	Rounding					
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,596,646		90,945,375		90,945,375	1
4		116		116	2
105	4,500	2,080		6,580	3
	90,000			90,000	4
	260,680			260,680	5
	1,833,010			1,833,010	6
-8		-196		-196	7
	1,241,500			1,241,500	8
160		2,504		2,504	9
	34,000			34,000	10
	18,942			18,942	11
150		2,550		2,550	12
111		8,151		8,151	13
					14
0	0	0	0	0	
4,463,898	3,900,510	117,977,145	0	121,877,655	
4,463,898	**3,900,510**	**117,977,145**	**0**	**121,877,655**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
3,199		137,557		137,557	2
112		3,624		3,624	3
1,862,958		26,863,067		26,863,067	4
	414,532			414,532	5
461		12,317		12,317	6
	3,347			3,347	7
					8
	-1			-1	9
					10
					11
					12
					13
					14
0	0	0	0	0	
4,463,898	3,900,510	117,977,145	0	121,877,655	
4,463,898	**3,900,510**	**117,977,145**	**0**	**121,877,655**	

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

OS 14 - RA, Energy Storage, Demand Response.

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

OS 14 - RA, Energy Storage, Demand Response.

Schedule Page: 310   Line No.: 14   Column: b

OS 4 - Long-Term Power Purchase agreements with renewable/alternative resources. "Long-Term" means 5 years or greater. The availability and reliability of energy delivered is on an as available basis.

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

OS 4 - Long-Term Power Purchase agreements with renewable/alternative resources. "Long-Term" means 5 years or greater. The availability and reliability of energy delivered is on an as available basis.

Schedule Page: 310.1   Line No.: 7   Column: b

OS 13 - Brokers

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	-638	5,990
5	(501) Fuel	-128	283
6	(502) Steam Expenses		
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses		
10	(506) Miscellaneous Steam Power Expenses	1,256,064	319,181
11	(507) Rents		
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	1,255,298	325,454
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	283,054	90,131
16	(511) Maintenance of Structures		
17	(512) Maintenance of Boiler Plant		1
18	(513) Maintenance of Electric Plant		
19	(514) Maintenance of Miscellaneous Steam Plant		36
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	283,054	90,168
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	1,538,352	415,622
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	16,762,761	17,984,550
25	(518) Fuel	35,745,202	37,537,023
26	(519) Coolants and Water	7,467,947	7,404,151
27	(520) Steam Expenses	4,699,892	5,574,270
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	5,407,315	4,879,562
31	(524) Miscellaneous Nuclear Power Expenses	24,655,027	28,835,653
32	(525) Rents		-4,466
33	TOTAL Operation (Enter Total of lines 24 thru 32)	94,738,144	102,210,743
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	2,932,579	2,677,183
36	(529) Maintenance of Structures	1,187,674	1,146,085
37	(530) Maintenance of Reactor Plant Equipment	9,220,271	8,351,707
38	(531) Maintenance of Electric Plant	7,133,673	6,663,462
39	(532) Maintenance of Miscellaneous Nuclear Plant	2,199,033	1,986,806
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	22,673,230	20,825,243
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	117,411,374	123,035,986
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	4,312,844	4,594,493
45	(536) Water for Power	5,224,514	4,102,974
46	(537) Hydraulic Expenses	2,285,758	2,386,848
47	(538) Electric Expenses	1,771,236	1,941,608
48	(539) Miscellaneous Hydraulic Power Generation Expenses	18,289,008	15,935,514
49	(540) Rents	1,169,165	1,224,466
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	33,052,525	30,185,903
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	5,097,395	3,982,235
54	(542) Maintenance of Structures	752,004	484,082
55	(543) Maintenance of Reservoirs, Dams, and Waterways	3,085,553	3,878,114
56	(544) Maintenance of Electric Plant	4,609,000	4,202,709
57	(545) Maintenance of Miscellaneous Hydraulic Plant	1,747,456	1,515,298
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	15,291,408	14,062,438
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	48,343,933	44,248,341

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	4,352,675	3,298,996
63	(547) Fuel	106,511,566	117,746,750
64	(548) Generation Expenses	3,767,546	5,163,038
65	(549) Miscellaneous Other Power Generation Expenses	27,041,364	36,363,740
66	(550) Rents	2,671,207	2,548,595
67	TOTAL Operation (Enter Total of lines 62 thru 66)	144,344,358	165,121,119
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2,625,851	3,223,343
70	(552) Maintenance of Structures	1,020,341	1,250,882
71	(553) Maintenance of Generating and Electric Plant	18,267,568	23,233,922
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,931,758	1,833,087
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	24,845,518	29,541,234
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	169,189,876	194,662,353
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	5,081,913,708	4,689,692,766
77	(556) System Control and Load Dispatching	1,136,216	1,181,489
78	(557) Other Expenses	31,473,189	35,579,434
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	5,114,523,113	4,726,453,689
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	5,451,006,648	5,088,815,991
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	8,095,108	7,489,433
84			
85	(561.1) Load Dispatch-Reliability	508,543	633,250
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	10,168,801	9,884,567
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services	36,792,220	39,115,071
89	(561.5) Reliability, Planning and Standards Development	4,373,750	5,180,971
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	22,200,415	22,183,203
94	(563) Overhead Lines Expenses	5,388,238	4,733,731
95	(564) Underground Lines Expenses	1,929,614	1,390,335
96	(565) Transmission of Electricity by Others	17,724,668	9,515,166
97	(566) Miscellaneous Transmission Expenses	57,280,232	11,247,928
98	(567) Rents	16,460,368	15,698,412
99	TOTAL Operation (Enter Total of lines 83 thru 98)	180,921,957	127,072,067
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	2,819,785	2,577,418
102	(569) Maintenance of Structures	199,964	401,543
103	(569.1) Maintenance of Computer Hardware	6,146,022	7,271,761
104	(569.2) Maintenance of Computer Software	20,377,530	18,769,249
105	(569.3) Maintenance of Communication Equipment	14,014,917	9,880,803
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	9,101,702	12,483,087
108	(571) Maintenance of Overhead Lines	26,435,467	39,274,929
109	(572) Maintenance of Underground Lines	323,169	391,308
110	(573) Maintenance of Miscellaneous Transmission Plant	-362,672	2,970,934
111	TOTAL Maintenance (Total of lines 101 thru 110)	79,055,884	94,021,032
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	259,977,841	221,093,099

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	15,546,490	15,395,604
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	15,546,490	15,395,604
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)	15,546,490	15,395,604
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	11,590,292	12,773,349
135	(581) Load Dispatching		
136	(582) Station Expenses	34,617,001	35,012,491
137	(583) Overhead Line Expenses	70,753,138	45,930,275
138	(584) Underground Line Expenses	7,884,780	8,321,772
139	(585) Street Lighting and Signal System Expenses	64,029	66,573
140	(586) Meter Expenses	21,206,498	23,885,682
141	(587) Customer Installations Expenses	17,934,596	19,052,441
142	(588) Miscellaneous Expenses	81,973,145	72,098,634
143	(589) Rents	2,683,060	2,410,103
144	TOTAL Operation (Enter Total of lines 134 thru 143)	248,706,539	219,551,320
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,559,657	2,386,348
147	(591) Maintenance of Structures	59,401	72,359
148	(592) Maintenance of Station Equipment	9,035,334	10,261,821
149	(593) Maintenance of Overhead Lines	174,140,149	205,205,056
150	(594) Maintenance of Underground Lines	52,472,744	49,116,266
151	(595) Maintenance of Line Transformers	3,725,848	6,523,161
152	(596) Maintenance of Street Lighting and Signal Systems	1,336,018	9,869,294
153	(597) Maintenance of Meters	5,162,059	5,471,532
154	(598) Maintenance of Miscellaneous Distribution Plant	35,728,990	14,948,606
155	TOTAL Maintenance (Total of lines 146 thru 154)	284,220,200	303,854,443
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	532,926,739	523,405,763
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	15,833,331	16,999,085
160	(902) Meter Reading Expenses	3,234,371	8,264,059
161	(903) Customer Records and Collection Expenses	100,051,506	96,966,838
162	(904) Uncollectible Accounts	20,234,492	13,097,848
163	(905) Miscellaneous Customer Accounts Expenses	2,040,739	16,457,757
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	141,394,439	151,785,587

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	10,054,083	63,636,756
168	(908) Customer Assistance Expenses	441,879,252	444,080,356
169	(909) Informational and Instructional Expenses	17,332,905	8,944,511
170	(910) Miscellaneous Customer Service and Informational Expenses	87	1,210
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	469,266,327	516,662,833
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	4,145,146	7,423,845
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses	-74,025	1,083,441
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	4,071,121	8,507,286
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	380,019,593	354,859,044
182	(921) Office Supplies and Expenses	243,397,352	249,803,334
183	(Less) (922) Administrative Expenses Transferred-Credit	153,376,384	145,897,634
184	(923) Outside Services Employed	54,239,013	54,121,017
185	(924) Property Insurance	16,155,127	14,497,978
186	(925) Injuries and Damages	2,996,146,771	117,581,984
187	(926) Employee Pensions and Benefits	115,626,278	142,806,958
188	(927) Franchise Requirements	113,911,175	110,632,750
189	(928) Regulatory Commission Expenses	11,239,506	16,012,736
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	6,438,097	5,718,074
192	(930.2) Miscellaneous General Expenses	23,890,761	34,422,373
193	(931) Rents	8,428,057	6,627,867
194	TOTAL Operation (Enter Total of lines 181 thru 193)	3,816,115,346	961,186,481
195	Maintenance		
196	(935) Maintenance of General Plant	18,830,965	13,296,044
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	3,834,946,311	974,482,525
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	10,709,135,916	7,500,148,688

Schedule Page: 320 Line No.: 71 Column: b

Account 553 - Included $556,877 of energy storage costs related to Mira Loma, Center and Grapeland.

Schedule Page: 320 Line No.: 71 Column: c

Account 553 - Included $611,100 of energy storage costs related to Mira Loma - Tesla

Schedule Page: 320 Line No.: 76 Column: b

Account 555 - Included $179,314 of energy storage costs related to Tesla Battery A and B.

Schedule Page: 320 Line No.: 76 Column: c

Account 555 - Included $165,502 of energy storage costs related to Teslas Battery A and B

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NON ASSOC:					
2	BUREAU INDIAN AFFAIRS	OS				
3						
4	COOPERATIVES:					
5	VALLEY ELECTRIC	RQ	218			
6						
7	MUNICIPALITIES:					
8	ANAHEIM, CITY OF FRINGE	OS				
9	BANNING, CITY OF FRINGE	OS				
10	LA DEPT OF WTR & PWR FRINGE	OS				
11	RIVERSIDE, CITY OF FRINGE	OS				
12						
13	OTHER PUBLIC AUTHORITIES:					
14	DEPARTMENT OF ENERGY - HOOVER -	LF	333			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	LA DEPARTMENT OF WATER & POWER -					
2	LOWER COLORADO RIVER	OS				
3	PASADENA, CITY OF - EXCH ENGY	EX	317			
4						
5	BROKERS/OTHER:					
6	ICE NGX CANADA INC	OS				
7	BGC FINANCIAL, LP	OS				
8	CHOICE POWER, LP	OS				
9	EQUUS ENERGY GROUP, LLC	OS				
10	EVOLUTION MARKETS FUTURES LLC	OS				
11	EVOLUTION MARKETS INC	OS				
12	INTERCONTINENTAL EXCHANGE	OS				
13	JPMORGAN CHASE BANK N.A.	OS				
14	MACQUARIE FUTURES USA INC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	SAGE REFINED PRODUCTS LTD	OS				
2	TULLETT PREBON AMERICAS CORP.	OS				
3						
4	GAS:					
5	EL PASO NATURAL GAS CO., L.L.C.	SF	WSPP-2			
6	INLAND EMPIRE ENERGY CENTER, LLC	SF	FERC VOL. 8			
7	SOUTHERN CALIFORNIA GAS COMPANY	SF	FERC VOL. 8			
8						
9	MUNICIPALITIES:					
10	CITY OF BURBANK WATER AND POWER	SF	WSPP-2			
11						
12	NON-ASSOCIATED UTILITIES:					
13	ARIZONA PUBLIC SERVICE COMPANY	SF	WSPP-2			
14	PACIFIC GAS & ELECTRIC COMPANY	SF	WSPP-2			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	PACIFICORP	SF	FERC Vol. 8			
2	PORTLAND GENERAL ELECTRIC	SF	FERC Vol. 8			
3	PUBLIC SERVICE COMPANY OF	SF	WSPP-2			
4	PUBLIC SERVICE COMPANY OF NEW	SF	WSPP-2			
5	SAN DIEGO GAS & ELECTRIC COMPANY	SF	WSPP-2			
6	TACOMA POWER	SF	WSPP			
7						
8	OTHER PUBLIC AUTHORITIES:					
9	BONNEVILLE POWER AUTHORITIES	SF	WSPP-2			
10	LOS ANGELES DEPARTMENT OF WATER	SF	WSPP-2			
11	POWEREX CORP.	SF	FERC Vol. 8			
12	SALT RIVER PROJECT AGRIC. IMPROVMT	SF	WSPP-2			
13	SEATTLE CITY LIGHT	SF	WSPP-2			
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	POWER MARKETERS DETAIL:					
2	ADVANCED MICROGRID SOLUTIONS, INC	OS				
3	AES ALAMITOS LLC					
4	AES HUNTINGTON BEACH LLC					
5	AES REDONDO BEACH LLC					
6	ALTAGAS POMONA ENERGY STORAGE	OS				
7	ARIZONA ELECTRIC POWER	SF	WSPP			
8	AVANGRID RENEWABLES, LLC	SF	FERC Vol. 8			
9	BP ENERGY COMPANY	SF	FERC Vol. 8			
10	BROOKFIELD ENERGY MARKETING LP	SF	WSPP			
11	CALPINE ENERGY SERVICES LP	SF	FERC Vol. 8			
12	CITIGROUP ENERGY INC	SF	FERC Vol. 8			
13	DIRECT ENERGY ENERGY BUSINESS LLC	SF	FERC Vol. 8			
14	DYNEGY MOSS LANDING LLC	LU	FERC Vol. 8			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EARTH NETWORKS, INC	OS				
2	ECOFACTOR INC.	OS				
3	EDF TRADING NORTH AMERICA, LLC	SF	FERC Vol. 8			
4	ENEL X NORTH AMERICA, INC.	OS				
5	ENERWISE GLOBAL TECHNOLOGIES, INC	OS				
6	ENGIE STORAGE SERVICES NA LLC	OS				
7	EXELON GENERATION COMPANY, LLC	SF	FERC Vol. 8			
8	GENON ENERGY MANAGEMENT, LLC	SF	FERC Vol. 8			
9	MACQUARIE ENERGY LLC	SF	FERC Vol. 8			
10	MORGAN STANLEY CAPITAL GROUP	SF	FERC Vol. 8			
11	NEVADA POWER COMPANY	SF	FERC Vol. 8			
12	OHMCONNECT CALIFORNIA, LLC	OS				
13	OHMCONNECT INC.	OS				
14	PPA GRAND JOHANNA LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SEMPRA GAS & POWER MARKETING LLC	SF	FERC Vol. 8			
2	SHELL ENERGY NO AMERICA US, L.P.	SF	FERC Vol. 8			
3	SONOMA CLEAN POWER AUTHORITY					
4	STEM INC.	OS				
5	TENASKA POWER SERVICES COMPANY	SF	WSPP			
6	TESLA INC.	OS				
7	TRANSALTA ENERGY MARKETING (US)	SF	WSPP-2			
8	TUCSON ELECTRIC POWER COMPANY	LU	WSPP-2			
9						
10	TOLLING UNITS:					
11	BE CA LLC	LU	FERC Vol. 8			
12	BLYTHE ENERGY LLC	LU	FERC Vol. 8			
13	CPV SENTINEL, LLC	LU	FERC Vol. 8			
14	CSU CHANNEL ISLANDS SITE AUTHORITY	IU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	EL SEGUNDO ENERGY CENTER LLC	LU	FERC Vol. 8			
2	LA PALOMA GENERATING COMPANY LLC	LU	FERC Vol. 8			
3	NRG LONG BEACH GENERATION LLC	LU	FERC Vol. 8			
4	O.L.S. ENERGY - CHINO (TOLL/RA)	LU	FERC Vol. 8			
5	WALNUT CREEK ENERGY LLC	LU	FERC Vol. 8			
6	WELLHEAD POWER DELANO	LU	FERC Vol. 8			
7						
8	NON UTILITIES: QUALIFYING FACILITY					
9	67RK 8ME, LLC	OS				
10	ADELANTO SOLAR II, LLC	OS				
11	ADELANTO SOLAR, LLC	OS				
12	ADERA SOLAR, LLC	OS				
13	ADOBE SOLAR LLC	OS				
14	ALGONQUIN SKIC 10 SOLAR, LLC	OS				
	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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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	ALTA MESA PWR PURCH CONTRACT	OS				
2	ALTA WIND I, LLC	OS				
3	ALTA WIND II, LLC	OS				
4	ALTA WIND III, LLC	OS				
5	ALTA WIND IV, LLC	OS				
6	ALTA WIND V, LLC	OS				
7	ALTA WIND VIII, LLC	OS				
8	ALTA WIND X, LLC	OS				
9	ALTA WIND XI, LLC	OS				
10	AMERICAN SOLAR GREENWORKS, LLC	OS				
11	AMTELOPE VALLEY SOLAR, LLC	OS				
12	ANNIE POWER, LLC	OS				
13	BECCA SOLAR, LLC	OS				
14	BERRY PETROLEUM COMPANY, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	BERRY PETROLEUM COMPANY,	OS				
2	BISHOP TUNGSTEN DEVELOPMENT LLC	OS				
3	BLYTHE SOLAR II, LLC	OS				
4	BROADVIEW ENERGY JN, LLC	OS				
5	BROADVIEW ENERGY KW, LLC	OS				
6	CALIENTE SPRINGS, LLC	OS				
7	CALIFORNIA PV ENERGY LLC	OS				
8	CALIFORNIA WATER SERVICE COMPANY	OS				
9	CALLEGUAS MUNICIPAL WATER	OS				
10	CALLEGUAS MWD	OS				
11	CALLEGUAS MWD (SANTA ROSA HYDRO)	OS				
12	CALLEGUAS MWD (SPRINGVILLE)	OS				
13	CAMERON RIDGE II	OS				
14	CATALINA SOLAR 2, LLC	OS				
	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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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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1	CE LEATHERS COMPANY	OS				
2	CED ATWELL ISLAND WEST, LLC	OS				
3	CED CORCORAN SOLAR 2 LLC	OS				
4	CED DUCOR 1, LLC	OS				
5	CED DUCOR 2, LLC	OS				
6	CED DUCOR 3, LLC	OS				
7	CED DUCOR 4, LLC	OS				
8	CENTRAL ANTELOPE DRY RANCH B, LLC	OS				
9	CENTRAL ANTELOPE DRY RANCH C, LLC	OS				
10	CENTRAL HYDROELECTRIC CORP.	OS				
11	CES DHS SOLAR, LLC (DHS SOLAR 1)	OS				
12	CES DHS SOLAR, LLC (DHS SOLAR 2)	OS				
13	CF SBC MASTER TENANT ONE LLC	OS				
14	CF SBC MASTER TENANT ONE LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	CHEVRON USA	OS				
2	CITIZEN SOLAR B, LLC	OS				
3	CITY OF LONG BEACH	OS				
4	CITY OF SANTA ANA	OS				
5	CITY OF SANTA BARBARA	OS				
6	CO OF LOS ANGELES - PITCHESS HONOR	OS				
7	CORAM ENERGY LLC	OS				
8	CORONAL LOST HILLS, LLC	OS				
9	COSO CLEAN POWER	OS				
10	COSO CLEAN POWER, LLC	OS				
11	COSO ENERGY DEVELOPERS	OS				
12	CSU CHANNEL ISLANDS SITE AUTHORITY	OS				
13	DANIEL M. BATES	OS				
14	DECADE ENERGY LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	DEEP SPRINGS COLLEGE	OS				
2	DEL RANCH, LTD., (NILAND #2)	OS				
3	DESERT POWER COMPANY	OS				
4	DESERT STATELINE LLC	OS				
5	DESERT SUNLIGHT LLC	OS				
6	DESERT WATER AGENCY	OS				
7	DESERT WATER AGENCY (SNOW CREEK)	OS				
8	DESERT WIND III PPC TRUST	OS				
9	DESERT WIND I PPC TRUST	OS				
10	DESERT WIND II PWR PURCH TRUST	OS				
11	DG SOLAR LESSEE II, LLC-E	OS				
12	DG SOLAR LESSEE II, LLC-PICO RIVERA	OS				
13	DG SOLAR LESSEE, LLC HESPERIA	OS				
14	DG SOLAR LESSEE, LLC (DUNCAN RD	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	DG SOLAR LESSEE, LLC (DUNCAN RD	OS				
2	DG SOLAR LESSEE, LLC (WHITE RD C)	OS				
3	DG SOLAR LESSEE, LLC (WHITE RD N)	OS				
4	DG SOLAR LESSEE, LLC (WHITE RD S)	OS				
5	DIAMOND VALLEY SOLAR LLC	OS				
6	DIFWIND FARMS LIMITED V	OS				
7	DILLON WIND LLC	OS				
8	DIVISION 1	OS				
9	DIVISION 2	OS				
10	DIVISION 3	OS				
11	DREAMER SOLAR LLC	OS				
12	DREW ENERGY, LLC	OS				
13	DUTCH ENERGY	OS				
14	E. F. OXNARD INCORPORATED	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EDOM HILLS PROJECT 1, LLC	OS				
2	EL CABO WIND LLC	OS				
3	ELK HILLS POWER, LLC	OS				
4	ELMORE, LTD	OS				
5	EXPRESSWAY SOLAR C2	OS				
6	EXXONMOBIL PRODUCTION COMPANY	OS				
7	FREEWAY SPRINGS	OS				
8	FTS MASTER TENANT 1 LLC(RODEO	OS				
9	FTS MASTER TENANT 1 LLC(RODEO	OS				
10	FTS MASTER TENANT 1 LLC(ESA)	OS				
11	FTS MASTER TENANT 1 LLC(ESB)	OS				
12	FTS MASTER TENANT 1 LLC(LDFRB)	OS				
13	FTS MASTER TENANT 2, LLC (SEPV18)	OS				
14	GARNET SOLAR POWER GENERATION	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	GEYSERS POWER COMPANY, LLC	OS				
2	GEYSERS POWER COMPANY, LLC	OS				
3	GFP ETHANOL, LLC DBA CALGREN	OS				
4	GOLDEN SOLAR, LLC	OS				
5	GOLDEN SPRINGS BUILDING F	OS				
6	GOLDEN SPRINGS DEV CO., LLC	OS				
7	GOLDEN SPRINGS DEVELOP CO.,	OS				
8	GOLDEN SPRINGS DEVELOP CO.,	OS				
9	GOLDEN SPRINGS DEVELOPMENT CO.,	OS				
10	GOLETA WATER DISTRICT	OS				
11	GOSHEN PHASE II LLC	OS				
12	GREEN BEANWORKS C LLC	OS				
13	GREEN BEANWORKS D LLC	OS				
14	HELIOCENTRIC, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	HI HEAD HYDRO INCORPORATED	OS				
2	HIGHLANDER SOLAR 1	OS				
3	HIGHLANDER SOLAR 2	OS				
4	HORSESHOE BEND WIND, LLC	OS				
5	HOUWELING NURSERIES OXNARD, INC.	OS				
6	INDUSTRY METROLINK PV1, LLC	OS				
7	INDUSTRY SOLAR POWER GENERATION	OS				
8	INLAND EMPIRE UTILITIES AGENCY	OS				
9	ISABELLA FISH FLOW HYDROELECTRIC	OS				
10	JACUMBA SOLAR, LLC	OS				
11	JRAM SOLAR 1 LLC	OS				
12	JRAM SOLAR 2 LLC	OS				
13	JRAM SOLAR 3 LLC	OS				
14	KAWEAH RIVER POWER AUTHORITY	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	KETTERING 1	OS				
2	KETTERING 2	OS				
3	KONA SOLAR LLC-PARK MERIDIAN 1	OS				
4	KONA SOLAR LLC-RANCHO CUCAMONGA	OS				
5	KONA SOLAR LLC-TERRA FRANCESCO 1	OS				
6	L A CO SANITATION DIST CSD2610	OS				
7	L-8 SOLAR PROJECT, LLC	OS				
8	LANCASTER LITTLE ROCK C LLC	OS				
9	LANCASTER WAD B, LLC (REMAT)	OS				
10	LITTLE ROCK-PHAM SOLAR, LLC	OS				
11	LOMA LINDA UNIVERSITY	OS				
12	LONE VALLEY SOLAR PARK I LLC	OS				
13	LONE VALLEY SOLAR PARK II LLC	OS				
14	LONGBOAT SOLAR, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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	LOWER TULE RIVER IRRIGATION	OS				
2	LUZ SOLAR PARTNERS LTD III	OS				
3	LUZ SOLAR PARTNERS LTD IV	OS				
4	LUZ SOLAR PARTNERS LTD. IX	OS				
5	LUZ SOLAR PARTNERS LTD V	OS				
6	LUZ SOLAR PARTNERS LTD V	OS				
7	LUZ SOLAR PARTNERS LTD VI	OS				
8	LUZ SOLAR PARTNERS LTD VII	OS				
9	LUZ SOLAR PARTNERS LTD VIII	OS				
10	MADELYN SOLAR	OS				
11	MAMMOTH PACIFIC L P II (MP2)	OS				
12	MARINO VENTURES LLC	OS				
13	MCCOY SOLAR, LLC	OS				
14	MESQUITE SOLAR 2, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	MITCHELL SOLAR	OS				
2	MM TAJIGUAS ENERGY LLC	OS				
3	MM TULARE ENERGY, LLC	OS				
4	MOGUL ENERGY PARTNERSHIP I, LLC	OS				
5	MONTE VISTA WATER DIST	OS				
6	MONTECITO WATER DIST	OS				
7	MORGAN LANCASTER I, LLC	OS				
8	MOUNTAINVIEW POWER PARTNERS IV,	OS				
9	MOUNTAINVIEW POWER PARTNERS, LLC	OS				
10	MUSTANG HILLS, LLC	OS				
11	NAVAJO SOLAR POWER GENERATION	OS				
12	NEWBERRY SOLAR 1 LLC	OS				
13	NEW-INDY ONTARIO, LLC	OS				
14	NEW-INDY OXNARD, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	NICOLIS, LLC	OS				
2	NORTH HURLBURT WIND, LLC	OS				
3	NORTH LANCASTER RANCH, LLC	OS				
4	NORTH PALM SPRINGS INVESTMENTS	OS				
5	NORTH PALM SPRINGS INVESTMENTS	OS				
6	NRG SOLAR BLYTHE LLC	OS				
7	NRG SOLAR OASIS LLC	OS				
8	OLS ENERGY - CHINO	OS				
9	ONE MIRACLE PROPERTY LLC	OS				
10	ONE TEN PARTNERS, LLC	OS				
11	ORANGE COUNTY SANITATION DISTRICT	OS				
12	ORION SOLAR SOLAR II	OS				
13	ORNI 18, LLC	OS				
14	OTOE SOLAR POWER GENERATION STAT	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PACIFIC ULTRA POWER CHINESE	OS				
2	PINYON PINES WIND I, LLC	OS				
3	PINYON PINES WINDS II, LLC	OS				
4	PORTAL RIDGE SOLAR B, LLC	OS				
5	POWHATAN SOLAR POWER GENERATION	OS				
6	PROCTER & GAMBLE PAPER PROD	OS				
7	PSOMASFMG LANCASTER SOLAR CREST	OS				
8	PSOMASFMG LANCASTER SOLAR CREST	OS				
9	PUMPJACK SOLAR I, LLC	OS				
10	PVN MILLIKEN, LLC	OS				
11	RADIANCE SOLAR 4 LLC	OS				
12	RADIANCE SOLAR 5 LLC	OS				
13	RE ADAMS EAST	OS				
14	RE COLUMBIA 3 LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RE GARLAND A, LLC	OS				
2	RE GARLAND, LLC	OS				
3	RE GASKELL WEST 1	OS				
4	RE ROSAMOND TWO LLC	OS				
5	RE TRANQUILITY 8 AZUL LLC	OS				
6	RE VICTOR PHELAN SOLAR ONE LLC	OS				
7	REGULUS SOLAR, LLC	OS				
8	REPUBLIC SERVICES OF SONOMA	OS				
9	RIDGETOP ENERGY, LLC (II)	OS				
10	RIO BRAVO FRESNO	OS				
11	RIO BRAVO ROCKLIN	OS				
12	RIO BRAVO SOLAR I	OS				
13	RIO BRAVO SOLAR II	OS				
14	RIO GRANDE LLC	OS				
	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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	RISING TREE WIND FARM III, LLC	OS				
2	RISING TREE WIND FARM, LLC	OS				
3	RIVERSIDE COUNTY WASTE MGMT	OS				
4	RUDY SOLAR	OS				
5	SALTON SEA POWER Generation #2	OS				
6	SALTON SEA POWER Generation #3	OS				
7	SALTON SEA POWER Generation #4	OS				
8	SAN BERNARDINO MWD	OS				
9	SAN GORGONIO WESTWINDS II,	OS				
10	SANDRA ENERGY LLC	OS				
11	SECOND IMPERIAL GEOTHERMAL CO.	OS				
12	SEPV1	OS				
13	SEPV II	OS				
14	SEPV MOJAVE WEST, LLC	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SEPV PALMDALE EAST, LLC	OS				
2	SEQUOIA PV 1 LLC (FARMERSVILLE 1)	OS				
3	SEQUOIA PV 1 LLC (FARMERSVILLE 2)	OS				
4	SEQUOIA PV 1 LLC (FARMERSVILLE 3)	OS				
5	SEQUOIA PV 1 LLC (TULARE 1)	OS				
6	SEQUOIA PV 1 LLC (TULARE 2)	OS				
7	SEQUOIA PV 2 LLC (HANFORD 1)	OS				
8	SEQUOIA PV 2 LLC (HANFORD 2)	OS				
9	SEQUOIA PV 3 LLC (PORTERVILLE 6)	OS				
10	SEQUOIA PV 3 LLC (PORTERVILLE 7)	OS				
11	SIERRA SOLAR GREENWORKS, LLC	OS				
12	SILVER STATE SOLAR POWER SOUTH,	OS				
13	SKY RIVER PTNRSHP - (WILDERNESS I)	OS				
14	SKY RIVER PTNRSHP - (WILDERNESS II)	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SKY RIVER PTNRSHP - (WILDERNESS III)	OS				
2	SOLAR PARTNERS I, LLC	OS				
3	SOLAR STAR CALIFORNIA XIII, LLC	OS				
4	SOLAR STAR XIX, LLC	OS				
5	SOLAR STAR XX, LLC	OS				
6	SOUTH HURLBURT WIND, LLC	OS				
7	SS SAN ANTONIO WEST LLC	OS				
8	SUMMER SOLAR A2 LLC	OS				
9	SUMMER SOLAR B2 LLC	OS				
10	SUMMER SOLAR C2 LLC	OS				
11	SUMMER SOLAR D2 LLC	OS				
12	SUNE SOLAR XVI LESSOR, LLC	OS				
13	SUNE W12DG-C, LLC	OS				
14	SUNRAY ENERGY 3, INC.	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	SUNSELECT PRODUCE	OS				
2	SYCAMORE COGENERATION COMPANY	OS				
3	SYCAMORE COGENERATION	OS				
4	TA-HIGH DESERT, LLC	OS				
5	TECHNI-CAST CORP	OS				
6	TEMESCAL CANYON (CREST)	OS				
7	TERMO COMPANY	OS				
8	TERRA-GEN 251 WIND, LLC (MONOLITH X)	OS				
9	TERRA-GEN 251 WIND, LLC (MONOLITH	OS				
10	TERRA-GEN 251 WIND, LLC (MONOLITH	OS				
11	TERRA-GEN 251 WIND, LLC(MONOLITH	OS				
12	TERRA-GEN DIXIE VALLEY, LLC	OS				
13	TERRA-GEN DIXIE VALLEY, LLC	OS				
14	TESORO REFINING & MARKETING	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	THE BANK OF NEW YORK MELLON TRUST	OS				
2	THREE VALLEYS MWD (FULTON)	OS				
3	THREE VALLEYS MWD (WILLIAMS)	OS				
4	TKO POWER, LLC (SOUTH BEAR CREEK)	OS				
5	TORO POWER 1, LLC	OS				
6	TORO POWER 2, LLC	OS				
7	TREEN SOLAR 2, LLC	OS				
8	TREEN SOLAR 1, LLC	OS				
9	TROPICO, LLC	OS				
10	TULARE PV I , LLC (EXETER 1)	OS				
11	TULARE PV I , LLC (EXETER 2)	OS				
12	TULARE PV I , LLC (EXETER 3)	OS				
13	TULARE PV I , LLC (IVANHOE 1)	OS				
14	TULARE PV I , LLC (IVANHOE 2)	OS				
	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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1	TULARE PV I , LLC (IVANHOE 3)	OS				
2	TULARE PV I , LLC (LINDSAY 1)	OS				
3	TULARE PV I , LLC (LINDSAY 3)	OS				
4	TULARE PV I , LLC (LINDSAY 4)	OS				
5	TULARE PV I , LLC (POTERVILLE 1)	OS				
6	TULARE PV I , LLC (POTERVILLE 2)	OS				
7	TULARE PV I , LLC (POTERVILLE 5)	OS				
8	TULE WIND LLC	OS				
9	U S BORAX INC.	OS				
10	UNITED WATER CONSERVATION	OS				
11	US TOPCO ENERGY, INC (SOCCER	OS				
12	USDA FOREST SERVICE SAN DIMAS	OS				
13	VEGA SOLAR, LLC	OS				
14	VENABLE SOLAR, LLC (NORTH)	OS				
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	VENABLE SOLAR, LLC (SOUTH)	OS				
2	VENTURA REGIONAL SANITATION DIST	OS				
3	VICTOR DRY FARM RANCH A, LLC	OS				
4	VICTOR DRY FARM RANCH B, LLC	OS				
5	VICTOR MESA LINDA B2 LLC	OS				
6	VICTOR MESA LINDA C2 LLC	OS				
7	VICTOR MESA LINDA D2 LLC	OS				
8	VICTOR MESA LINDA E2 LLC	OS				
9	VICTORY GARDEN/PHASE IV PARTNER	OS				
10	VICTORY GARDEN/PHASE IV PARTNER	OS				
11	VICTORY GARDEN/PHASE IV PARTNER	OS				
12	VOYAGER SOLAR 1 LLC	OS				
13	VOYAGER SOLAR 2 LLC	OS				
14	VOYAGER SOLAR 3 LLC	OS				
	Total					

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WALNUT VALLEY WATER DISTRICT	OS				
2	WATSON COGENERATION COMPANY	OS				
3	WHEELABRATOR NORWALK ENERGY CO	OS				
4	WHITE MOUNTAIN RANCH LLC	OS				
5	WILDWOOD SOLAR I	OS				
6	WILDWOOD SOLAR I, LLC	OS				
7	WINDLAND REFRESH 1, LLC	OS				
8	WINDLAND REFRESH 2, LLC	OS				
9	WINDSTAR ENERGY LLC	OS				
10	YAVI ENERGY (EASTWIND)	OS				
11	CALIFORNIA ISO - NET					
12	INDEPENDENT EVALUATOR COSTS					
13	VARIOUS ENERGY SETTLEMENT REFUND					
14	DERIVATIVE CONVERSION					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	WECC STATUTORY COSTS					
2	HEDGING-CONGESTION REVENUE					
3	HEDGING-REALIZED					
4	HEDGING-UNREALIZED					
5	REC INVENTORY					
6	REMAT/BIOMAT APPLICATION FEES	OS				
7	WECC WREGIS CERTIFICATE					
8	CALIFORNIA AIR RESOURCE BOARD					
9						
10						
11	ROUNDING					
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
1,314				102,881		102,881	2
							3
							4
					10,800	10,800	5
							6
							7
13				3,749		3,749	8
98				24,499		24,499	9
-1,611				-154,920		-154,920	10
31				2,283		2,283	11
							12
							13
180,072			5,124,690	2,380,627	-2,231,788	5,273,529	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-2,316				868		868	1
					138,218	138,218	2
		20					3
							4
							5
					32,237	32,237	6
					-207,897	-207,897	7
					15,013	15,013	8
					18,522	18,522	9
					-213	-213	10
					1,564	1,564	11
					87,496	87,496	12
					4,150,322	4,150,322	13
					129,194	129,194	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					116	116	1
					33,098	33,098	2
							3
							4
				633,322	1,355,508	1,988,830	5
			111,767			111,767	6
				775,764	31,514,254	32,290,018	7
							8
							9
6,158				191,922		191,922	10
							11
							12
44,174				1,181,474		1,181,474	13
			1,510,000			1,510,000	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
451,685				12,410,052		12,410,052	1
124,626				5,656,425		5,656,425	2
40,800				1,272,000		1,272,000	3
5,200				131,200		131,200	4
3,400				101,800		101,800	5
19,364				684,265		684,265	6
							7
							8
632,188				22,518,379		22,518,379	9
200				6,800		6,800	10
428,915				21,471,963		21,471,963	11
100,997				3,290,281		3,290,281	12
7,794				284,236		284,236	13
							14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
							1
			-23,800			-23,800	2
			51,365,209			51,365,209	3
			11,537,103			11,537,103	4
			18,245,802			18,245,802	5
			5,922,466			5,922,466	6
2,400				85,000		85,000	7
716,616			137,513	21,550,639		21,688,152	8
244,656				10,156,368		10,156,368	9
6,570				202,015		202,015	10
29,572			47,446,358	798,261		48,244,619	11
278,239				12,549,677		12,549,677	12
			238,630			238,630	13
			8,208,000			8,208,000	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
			-25,840			-25,840	1
					-21,600	-21,600	2
28,345				836,153		836,153	3
			48,000			48,000	4
			1,672,171			1,672,171	5
			11,532			11,532	6
311,635				9,862,720		9,862,720	7
			23,327,762			23,327,762	8
4,400				117,600		117,600	9
494,909			1,770,000	15,169,087		16,939,087	10
800				34,400		34,400	11
			788,859			788,859	12
			9,060			9,060	13
			335,760			335,760	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
30,725				1,368,780		1,368,780	1
95,188				3,596,470		3,596,470	2
			22,440			22,440	3
			5,838			5,838	4
16,225				439,031		439,031	5
			8,808			8,808	6
77,212				2,918,963		2,918,963	7
26,200				736,550		736,550	8
							9
							10
450,266			79,465,590	31,366,702		110,832,292	11
2,816,289			54,587,544	86,016,670		140,604,214	12
486,536			148,024,118	38,453,192		186,477,310	13
8,805			2,239,587	690,821	-12,783	2,917,625	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
1,143,636			115,881,952	64,609,305	901	180,492,158	1
			10,740,000			10,740,000	2
			85,948			85,948	3
8,613			2,830,739	1,731,185	-136	4,561,788	4
394,319			96,810,340	35,551,517		132,361,857	5
5,213			7,955,146	506,916		8,462,062	6
							7
							8
39,079			-318,417	2,888,337		2,569,920	9
18,970				1,384,981		1,384,981	10
61,539				5,000,202		5,000,202	11
43,381				3,157,934		3,157,934	12
50,561				6,671,214		6,671,214	13
21,819				1,656,879		1,656,879	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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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)	
15,375			395,379	529,496		924,875	1
397,163				45,548,180	-1,781,508	43,766,672	2
346,569				39,704,305	-1,619,442	38,084,863	3
358,965				40,894,664	-1,629,060	39,265,604	4
177,368				20,357,851	-1,112,271	19,245,580	5
282,597				32,583,038	-1,838,291	30,744,747	6
275,908				32,882,039		32,882,039	7
370,399				39,593,263	-1,975,084	37,618,179	8
273,141				30,038,068	-1,294,344	28,743,724	9
16,926				1,615,986		1,615,986	10
8,625				542,915		542,915	11
4,249				598,738		598,738	12
4,138				585,272		585,272	13
296,658			3,162,642	14,325,860	-192,246	17,296,256	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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)	
300,812			2,196,371	15,154,741	-87,338	17,263,774	1
1,300				121,685	-35	121,650	2
345,326				20,777,620	-12,341	20,765,279	3
695,875				33,429,508		33,429,508	4
552,698				26,535,916		26,535,916	5
1,316				95,551	-320	95,231	6
5,156				824,417		824,417	7
304				26,449		26,449	8
5,896				596,329		596,329	9
				1		1	10
275				24,522		24,522	11
1,343				120,293		120,293	12
33,918				1,881,520		1,881,520	13
84,060			-170,628	4,952,064		4,781,436	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
304,682			7,526,346	11,323,067		18,849,413	1
68,927			-213,740	4,368,527		4,154,787	2
50,523				5,220,127		5,220,127	3
52,520				2,890,412		2,890,412	4
52,346				2,881,312		2,881,312	5
39,267				2,162,523		2,162,523	6
52,432				2,885,910		2,885,910	7
8,386				651,792		651,792	8
39,573				3,523,983		3,523,983	9
18,782			817,117	661,738		1,478,855	10
2,459				293,765		293,765	11
3,606				430,072		430,072	12
3,244				428,490		428,490	13
1,260				158,724		158,724	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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75,809			490,336	3,223,997		3,714,333	1
11,694				940,921		940,921	2
159,564			4,019,567	14,306,975		18,326,542	3
3			4	103		107	4
520				56,803		56,803	5
124,293			3,495,976	4,432,087		7,928,063	6
11,532				824,082		824,082	7
52,861				4,319,420		4,319,420	8
411,644				32,938,244		32,938,244	9
482,615				39,137,768		39,137,768	10
285,436			9,608,501	11,487,759		21,096,260	11
35,066			523,594	1,173,510		1,697,104	12
455			10,299	16,762		27,061	13
					-16,000	-16,000	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
18			25	1,006		1,031	1
313,571			8,015,552	11,738,172		19,753,724	2
1,639			11,967	121,967		133,934	3
668,216				104,124,405		104,124,405	4
623,891				93,720,148		93,720,148	5
2,895				263,608		263,608	6
238			77	19,536	-1,680	17,933	7
57,898			1,289,208	2,128,268		3,417,476	8
62,371			1,281,823	2,281,225		3,563,048	9
176,752			3,773,662	6,344,588		10,118,250	10
1,891				265,690		265,690	11
1,643				224,797		224,797	12
3,332				486,016		486,016	13
3,698				462,915		462,915	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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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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.
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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)	
2,496				311,892		311,892	1
3,983				499,694		499,694	2
3,936				493,421		493,421	3
3,806				483,928		483,928	4
2,364				309,549		309,549	5
29				304		304	6
138,792				9,779,600		9,779,600	7
2,748				350,499		350,499	8
1,934				247,931		247,931	9
2,042				259,567		259,567	10
4,336				606,324		606,324	11
2,632				348,635		348,635	12
21,067			508,271	742,305		1,250,576	13
157,221			10,115,423	7,418,550		17,533,973	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
37,513			184,626	1,216,620	-77,746	1,323,500	1
994,468				49,788,396		49,788,396	2
1,072,960			21,877,633	35,742,679		57,620,312	3
284,362			7,936,189	10,724,526		18,660,715	4
3,731				470,532		470,532	5
			27	28,719		28,746	6
3,380				439,410		439,410	7
3,816				486,152		486,152	8
3,841				487,710		487,710	9
5,152				401,583		401,583	10
4,545				353,836		353,836	11
13,440				1,192,426		1,192,426	12
5,906				594,978		594,978	13
8,451				809,860		809,860	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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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)	
-140,690				-1		-1	1
2,406,600				159,095,001		159,095,001	2
37,098				2,182,375	-26,806	2,155,569	3
3,224				426,562		426,562	4
2,396				319,672		319,672	5
3,669				876,756		876,756	6
2,640				412,746		412,746	7
3,105				495,024		495,024	8
3,977				523,094		523,094	9
300				31,356		31,356	10
375,342				38,333,498		38,333,498	11
2,615				185,876		185,876	12
2,436				151,500		151,500	13
3,211				436,669		436,669	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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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)	
1,063			7,775	63,767		71,542	1
34,254				3,132,501		3,132,501	2
24,745				2,213,706		2,213,706	3
653,172				66,600,768	3,195,616	69,796,384	4
44,588				2,512,574	-97,777	2,414,797	5
2,851				693,432		693,432	6
4,157				581,593		581,593	7
-8			-6	-296		-302	8
3,811				361,372		361,372	9
50,670				3,259,515		3,259,515	10
4,275				602,376		602,376	11
4,325				600,811		600,811	12
2,965				416,442		416,442	13
26,938			1,391,272	934,599		2,325,871	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
2,038				260,478		260,478	1
2,029				256,040		256,040	2
2,384				310,980		310,980	3
3,318				423,140		423,140	4
2,429				315,963		315,963	5
-2			2	2,855		2,857	6
3,068				408,735		408,735	7
13,642				861,160		861,160	8
8,559				708,488		708,488	9
8,519				866,481		866,481	10
1,399			4,633	54,706		59,339	11
24,389				1,763,331		1,763,331	12
51,875				3,762,194		3,762,194	13
60,651				3,782,477		3,782,477	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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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)	
501				51,158		51,158	1
43,700				2,813,478	-9,081	2,804,397	2
44,256				2,850,231	-9,081	2,841,150	3
154,220			16,453,561	6,737,405		23,190,966	4
535			82,470	24,580		107,050	5
47,931				3,179,683		3,179,683	6
43,402			5,091,459	1,923,987		7,015,446	7
39,587			5,007,136	1,788,282		6,795,418	8
147,718			14,805,003	6,468,195		21,273,198	9
2,896				361,165		361,165	10
62,439			1,048,960	2,440,533		3,489,493	11
651				80,043		80,043	12
701,728				71,262,433		71,262,433	13
285,268				17,007,143	-7,515	16,999,628	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
3,981				474,012		474,012	1
24,049				2,061,686		2,061,686	2
7,262				647,314		647,314	3
-5				-171	-30,000	-30,171	4
954				94,364		94,364	5
31			482	1,160		1,642	6
3,816				358,317		358,317	7
172,654				19,111,483		19,111,483	8
194,234				18,714,611		18,714,611	9
306,492				36,286,266		36,286,266	10
4,174				593,919		593,919	11
1,625				226,535		226,535	12
46,495			283,048	2,303,364	-124,789	2,461,623	13
91,755			586,138	4,648,302	-491,126	4,743,314	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
50,505				3,811,355		3,811,355	1
571,986				57,471,120	2,944,242	60,415,362	2
38,669				3,490,366		3,490,366	3
4,137				624,214		624,214	4
6,060				917,005		917,005	5
43,957				4,979,905		4,979,905	6
58,508			-363,322	4,595,029		4,231,707	7
15,068			171,326	462,371		633,697	8
1,538				204,648		204,648	9
6,379				479,232		479,232	10
670			6,174	29,485		35,659	11
19,150				1,506,481		1,506,481	12
52,525				3,118,941		3,118,941	13
3,629				518,057		518,057	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
142,076			-10,159	15,953,813	-9,081	15,934,573	1
337,460				41,537,404	-2,072,000	39,465,404	2
242,957				29,929,281	-1,628,000	28,301,281	3
55,148				3,701,194		3,701,194	4
4,452				623,481		623,481	5
377,275			11,488,960	14,946,152		26,435,112	6
3,592				449,696		449,696	7
3,599				453,281		453,281	8
50,775			-114,845	3,735,776		3,620,931	9
5,456				515,792		515,792	10
3,357				481,504		481,504	11
3,377				484,415		484,415	12
51,142				4,240,504		4,240,504	13
25,186				3,185,675		3,185,675	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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)	
59,996				4,232,123		4,232,123	1
540,546			-87,646	30,865,780		30,778,134	2
52,674			-21,328	3,772,288	-389,120	3,361,840	3
49,079				7,888,926		7,888,926	4
55,155			-153,081	3,851,934	-56,200	3,642,653	5
47,223				7,584,500		7,584,500	6
163,529				21,468,139	-311,922	21,156,217	7
23,191			-3,471	1,589,578		1,586,107	8
55,566			1,491,258	1,943,758		3,435,016	9
190,397			-30,099	16,644,376		16,614,277	10
178,474			-29,089	20,003,853		19,974,764	11
52,998				2,825,692		2,825,692	12
52,637			-105,945	2,792,936		2,686,991	13
11,416				1,733,525		1,733,525	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					-838,250	-838,250	1
					-670,600	-670,600	2
-44				-3,564		-3,564	3
4,199				514,782		514,782	4
100,792			3,286,138	3,726,475		7,012,613	5
309,198			9,355,688	11,462,917		20,818,605	6
280,259			5,334,446	10,230,088		15,564,534	7
219			2,624	9,513		12,137	8
25,792				1,428,986		1,428,986	9
4,149				580,947		580,947	10
87,014			867,350	2,763,265		3,630,615	11
5,185				877,147		877,147	12
4,949				906,133		906,133	13
58,238				4,033,048		4,033,048	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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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)	
27,607				1,866,976		1,866,976	1
2,715				353,812		353,812	2
2,688				351,685		351,685	3
2,558				334,666		334,666	4
2,765				358,453		358,453	5
2,567				325,467		325,467	6
2,792				364,540		364,540	7
2,744				363,794		363,794	8
2,857				377,441		377,441	9
2,932				383,624		383,624	10
45,404				3,815,648		3,815,648	11
715,235				94,751,151		94,751,151	12
58,379			856,588	2,028,775		2,885,363	13
29,449			444,295	1,084,790		1,529,085	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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36,533			529,747	1,398,331		1,928,078	1
277,322				45,393,924	-3,170,000	42,223,924	2
286,015				35,444,855		35,444,855	3
906,551				101,063,732	-10,621,223	90,442,509	4
793,990				88,191,605	-9,378,777	78,812,828	5
623,702				63,710,707	3,252,565	66,963,272	6
2,852				647,947		647,947	7
3,855				490,748		490,748	8
3,844				489,961		489,961	9
3,851				489,828		489,828	10
2,314				294,824		294,824	11
1,680				224,991		224,991	12
1,755				274,680		274,680	13
37,714				1,740,578		1,740,578	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

PURCHASED POWER(Account 555) (Continued)
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9,536				570,051	-12,500	557,551	1
1,369,121			11,197,163	71,224,481	-828,227	81,593,417	2
57,027			10,461,701	3,258,671	-12,608	13,707,764	3
53,957				8,017,188		8,017,188	4
342				20,095	-14,000	6,095	5
2,196				294,250		294,250	6
1			9	38		47	7
264				4,653		4,653	8
178				3,178		3,178	9
269				4,820		4,820	10
184				3,323		3,323	11
252,122			4,016,573	8,223,824		12,240,397	12
242,478				25,061,528		25,061,528	13
219,236			1,499,818	10,122,103	-237,601	11,384,320	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

PURCHASED POWER(Account 555) (Continued)
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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)	
-8			-6	-244		-250	1
539			7,850	22,544	-17,500	12,894	2
1,590			14,519	60,227	-17,500	57,246	3
3,736			-12,872	232,872		220,000	4
3,859				544,041		544,041	5
1,392				194,102		194,102	6
2,712				382,762		382,762	7
2,761				388,351		388,351	8
35,632				2,773,296		2,773,296	9
1,938				251,746		251,746	10
1,927				249,692		249,692	11
2,876				372,998		372,998	12
2,766				361,428		361,428	13
945				122,782		122,782	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
2,702				354,885		354,885	1
2,755				358,905		358,905	2
2,736				358,734		358,734	3
1,750				232,150		232,150	4
1,895				247,833		247,833	5
1,922				250,986		250,986	6
2,903				380,347		380,347	7
340,630			-339,695	19,220,209	-11,755	18,868,759	8
109,665			527,918	5,390,666	-150,685	5,767,899	9
82			1,299	2,859		4,158	10
5,858				507,054		507,054	11
329				30,017		30,017	12
51,909				3,956,153		3,956,153	13
3,438				451,607		451,607	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
3,476				457,063		457,063	1
220				-125,349		-125,349	2
10,512				971,065		971,065	3
10,594				980,515		980,515	4
3,801				475,506		475,506	5
3,835				479,513		479,513	6
3,831				479,004		479,004	7
3,802				476,283		476,283	8
11,218			161,621	427,484		589,105	9
6,378			106,165	240,751		346,916	10
10,404			117,039	386,923		503,962	11
3,975				576,393		576,393	12
4,121				602,771		602,771	13
2,784				408,361		408,361	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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)	
351				31,489		31,489	1
2,188,678			17,890,230	130,182,206	-1,208,627	146,863,809	2
-763			-2,497	-38,991		-41,488	3
959				86,438		86,438	4
41,593				2,274,084		2,274,084	5
50,194			-115,868	3,739,278		3,623,410	6
14,704			-2,902	1,193,155		1,190,253	7
18,253				1,278,799		1,278,799	8
288,754				32,239,690		32,239,690	9
7,436				637,682		637,682	10
30,283,091			9,467,158	1,892,029,056	-358,553,919	1,542,942,295	11
					236,420	236,420	12
					-42,692,901	-42,692,901	13
					-203,044,951	-203,044,951	14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
					9,308,261	9,308,261	1
					-39,339,249	-39,339,249	2
					-25,744,427	-25,744,427	3
					-42,826,131	-42,826,131	4
					393,007	393,007	5
					270,666	270,666	6
					208,961	208,961	7
				-16,692,488		-16,692,488	8
							9
							10
-7			2	-14	-1	-13	11
							12
							13
							14
72,293,537		20	915,629,689	4,867,753,091	-701,469,072	5,081,913,708	

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

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 LOWER COLORADO RIVER MULTI-SPECIES CONSERVATION PROGRAM.

OS13 BROKERS

OS14 RA, ENERGY STORAGE, DEMAND RESPONSE

Schedule Page: 326 Line No.: 2 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

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

N/A

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

N/A

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

N/A

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

Facility Charges.

Schedule Page: 326 Line No.: 8 Column: b

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

OS 8 - Please reference page 326 Line 1 Column (b).

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

Termination Date: 9/30/2067

Schedule Page: 326 Line No.: 14 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 2 Column: b
OS 12 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 2 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 6 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 6 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 7 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 7 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 8 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 8 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 9 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 10 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 10 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 11 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 11 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 12 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 12 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 13 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 13 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.1 Line No.: 14 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.1 Line No.: 14 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.2 Line No.: 1 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.2 Line No.: 1 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.2 Line No.: 2 Column: b
OS 13 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.2 Line No.: 2 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.2 Line No.: 5 Column: l

Net Gas Purchases Plus Imbalances.

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

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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

OS 14 - Please reference page 326 Line 1 Column (b).

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

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 1 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

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

OS 14 - Please reference page 326 Line 1 Column (b).

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

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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

OS 14 - Please reference page 326 Line 1 Column (b).

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

OS 14 - Please reference page 326 Line 1 Column (b).

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

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 12 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 13 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.5 Line No.: 14 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.6 Line No.: 4 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.6 Line No.: 6 Column: b

OS 14 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.6 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.7 Line No.: 1 Column: l

California ISO costs.

Schedule Page: 326.7 Line No.: 4 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.7 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.7 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 3 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 4 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 5 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 6 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 8 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 9 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.8 Line No.: 14 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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.: 1 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.9 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.9 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.9 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.9 Line No.: 6 Column: l
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
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Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

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OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 12 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.26 Line No.: 14 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.27 Line No.: 1 Column: b

OS 2 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 2 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 3 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.27 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 11 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 12 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 13 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.27 Line No.: 14 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 1 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 2 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 3 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 4 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 8 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.28 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.28 Line No.: 9 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.28 Line No.: 10 Column: b
OS 1 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.28 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 2 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 3 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 5 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 6 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 7 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 8 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 9 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 10 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 11 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 12 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 13 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.29 Line No.: 14 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.30 Line No.: 1 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.30 Line No.: 2 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.30 Line No.: 2 Column: l
Expenses related to collateral requirements, trust fund management and miscellaneous other expense.
Schedule Page: 326.30 Line No.: 3 Column: b
OS 2 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.30 Line No.: 4 Column: b
OS 4 - Please reference page 326 Line 1 Column (b).
Schedule Page: 326.30 Line No.: 5 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 6 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 7 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 8 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 9 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 10 Column: b

OS 4 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.30 Line No.: 11 Column: l

California ISO Costs.

Schedule Page: 326.30 Line No.: 12 Column: l

Independent Evaluator Costs.

Schedule Page: 326.30 Line No.: 13 Column: l

Various Energy Settlement Refunds.

Schedule Page: 326.30 Line No.: 14 Column: l

Capital Lease under GAAP.

Schedule Page: 326.31 Line No.: 1 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Schedule Page: 326.31 Line No.: 2 Column: l

Unrealized Gain / Loss on Financial Futures or Options.

Schedule Page: 326.31 Line No.: 3 Column: l

Realized Gain / Loss on Financial Futures or Options.

Schedule Page: 326.31 Line No.: 4 Column: l

Unrealized Gain / Loss on Financial Futures or Options.

Schedule Page: 326.31 Line No.: 5 Column: l

Renewable Energy Credits.

Schedule Page: 326.31 Line No.: 6 Column: b

OS 13 - Please reference page 326 Line 1 Column (b).

Schedule Page: 326.31 Line No.: 6 Column: l

Remat/Biomat Application Fees.

Schedule Page: 326.31 Line No.: 7 Column: l

Expenses related to collateral requirements, trust fund management and miscellaneous other expense.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Pasadena	Various	City of Pasadena	AD
2	City of Riverside	Various	City of Riverside	OLF
3	City of Riverside	Various	City of Riverside	AD
4	City of Riverside	Various	City of Riverside	OLF
5	City of Riverside	Various	City of Riverside	AD
6	City of Riverside	Various	City of Riverside	OLF
7	City of Riverside	Various	City of Riverside	AD
8	City of Riverside	Various	City of Riverside	OLF
9	City of Riverside	Various	City of Riverside	AD
10	City of Vernon	Various	City of Vernon	OLF
11	City of Vernon	Various	City of Vernon	OLF
12	City of Vernon	Various	City of Vernon	OLF
13	City of Azusa	Various	City of Azusa	OLF
14	City of Azusa	Various	City of Azusa	AD
15	City of Azusa	Various	City of Azusa	OLF
16	City of Azusa	Various	City of Azusa	AD
17	City of Azusa	City of Pasadena	City of Azusa	OLF
18	City of Azusa	City of Pasadena	City of Azusa	AD
19	City of Azusa	Various	City of Azusa	OLF
20	City of Azusa	Various	City of Azusa	AD
21	City of Azusa	Various	City of Azusa	AD
22	City of Colton	Various	City of Colton	OLF
23	City of Colton	Various	City of Colton	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	AD
28	City of Colton	Various	City of Colton	OLF
29	City of Colton	Various	City of Colton	AD
30	City of Colton	Various	City of Colton	AD
31	City of Banning	Various	City of Banning	OLF
32	City of Banning	Various	City of Banning	AD
33	City of Banning	Various	City of Banning	OLF
34	City of Banning	Various	City of Banning	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Banning	Various	City of Banning	OLF
2	City of Banning	Various	City of Banning	AD
3	City of Banning	Various	City of Banning	OLF
4	City of Banning	Various	City of Banning	AD
5	Department of Water Resources	Various	Department of Water Resources	OLF
6	Department of Water Resources	Various	Department of Water Resources	OLF
7	Department of Water Resources	Various	Department of Water Resources	OLF
8	Reliant Energy Coolwater, LLC	Alta Power Generation	ISO	OLF
9	Reliant Energy Mandalay, LLC	Ocean Vista Power Generation	ISO	OLF
10	Reliant Energy Ormond Bch, LLC	Ormond Beach Generation	ISO	OLF
11	A.E.S. Huntington Bch. L.L.C.	A.E.S. Huntington Beach	ISO	OLF
12	High Desert Power Trust	Various	High Desert Power Trust	OLF
13	Inland Empire Energy Center	Various	Inland Empire Energy Center	OLF
14	Department of Water Resources	Various	Department of Water Resources	OLF
15	Department of Water Resources	Various	Department of Water Resources	OLF
16	Department of Water Resources	Various	Department of Water Resources	OLF
17	Department of Water Resources	Various	Department of Water Resources	OLF
18	Department of Water Resources	Various	Department of Water Resources	OLF
19	Metropolitan Water District	Department of Water Resources	Metropolitan Water District	OLF
20	City of Los Angeles	Various	City of Los Angeles	OLF
21	City of Los Angeles	Various	City of Los Angeles	AD
22	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPCO	OLF
23	Southern California Water Company	Various	Southern California Water Co	OLF
24	M-S-R Public Power Authority	Various	Pacific Gas & Electric Company	OLF
25	City of Azusa	Various	City of Azusa	OLF
26	City of Riverside	Various	City of Riverside	OLF
27	City of Banning	Various	City of Banning	OLF
28	City of Banning	Various	City of Banning	AD
29	City of Azusa	Various	City of Azusa	OLF
30	City of Azusa	Various	City of Azusa	AD
31	City of Colton	Various	City of Colton	OLF
32	City of Colton	Various	City of Colton	AD
33	Southern California Water Company	Southern California Water Co	Southern California Water Company	OLF
34	Southern California Water Company	Southern California Water Co	Southern California Water Company	AD
	TOTAL			

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
2	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
3	City of Corona	Various	City of Corona	OLF
4	City of Corona	Various	City of Corona	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	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
12	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
13	City of Corona	Various	City of Corona	OLF
14	City of Corona	Various	City of Corona	AD
15	City of Corona	Various	City of Corona	OLF
16	City of Corona	Various	City of Corona	AD
17	City of Moreno Valley	Various	City of Moreno Valley	OLF
18	City of Moreno Valley	Various	City of Moreno Valley	AD
19	City of Corona	Various	City of Corona	OLF
20	City of Corona	Various	City of Corona	AD
21	City of Moreno Valley	Various	City of Moreno Valley	OLF
22	City of Moreno Valley	Various	City of Moreno Valley	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	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
30	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
31	City of Moreno Valley	Various	City of Moreno Valley	OLF
32	City of Moreno Valley	Various	City of Moreno Valley	AD
33	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
34	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
	TOTAL			

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Sthwest Trans Elec Pwr Coop/AEPCO	Various	City of Anza	OLF
2	Sthwest Trans Elec Pwr Coop/AEPCO	Various	City of Anza	AD
3	City of Corona	Various	City of Corona	OLF
4	City of Corona	Various	City of Corona	AD
5	Arizona Public Service	Various	Arizona Public Service	OLF
6	Arizona Public Service	Various	Arizona Public Service	AD
7	City of Victorville	Various	City of Victorville	OLF
8	City of Victorville	Various	City of Victorville	AD
9	City of Victorville	Various	City of Victorville	OLF
10	City of Victorville	Various	City of Victorville	AD
11	City of Moreno Valley	Various	City of Moreno Valley	OLF
12	City of Moreno Valley	Various	City of Moreno Valley	AD
13	City of Colton	Various	City of Colton	OLF
14	Department of Water Resources	Various	Department of Water Resources	OLF
15	Department of Water Resources	Various	Department of Water Resources	AD
16	Department of Water Resources	Various	Department of Water Resources	OLF
17	Department of Water Resources	Various	Department of Water Resources	AD
18	Department of Water Resources	Various	Department of Water Resources	OLF
19	Department of Water Resources	Various	Department of Water Resources	AD
20	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPC	OLF
21	Sthwest Trans Elec Pwr Coop/AEPCO	Various	Sthwest Trans Elec Pwr Coop/AEPC	AD
22	Southern California Water Company	Various	Southern California Water Company	OLF
23	Southern California Water Company	Various	Southern California Water Company	AD
24	Industry Urban Development Agency	Various	Industry Urban Development Agency	OLF
25	Industry Urban Development Agency	Various	Industry Urban Development Agency	AD
26	City of Corona	Various	City of Corona	OLF
27	City of Corona	Various	City of Corona	AD
28	Department of Water Resources	Various	Department of Water Resources	OLF
29	Department of Water Resources	Various	Department of Water Resources	AD
30	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	OLF
31	City of Rancho Cucamonga	Various	City of Rancho Cucamonga	AD
32	City of Moreno Valley	Various	City of Moreno Valley	OLF
33	City of Moreno Valley	Various	City of Moreno Valley	AD
34	City of Victorville	Various	City of Victorville	OLF
	TOTAL			

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	City of Victorville	Various	City of Victorville	AD
2	City of Victorville	Various	City of Victorville	OLF
3	City of Victorville	Various	City of Victorville	AD
4	ISO Wheeling	N/A	N/A	OS
5	ISO Wheeling	N/A	N/A	AD
6	Mojave Solar LLC	Mojave Solar	ISO	OLF
7	City of Industry	Various	City of Industry	OLF
8	City of Industry	Various	City of Industry	AD
9	Southwest Trans Elec Pwr Coop-AEPCO	Various	SouthwestTransElecPwr Coop-AEPCO	AD
10	City of Riverside	Various	City of Riverside	AD
11	City of Industry	Various	City of Industry	OLF
12	City of Industry	Various	City of Industry	AD
13	Department of Water Resources	Various	Department of Water Resources	OLF
14	Department of Water Resources	Various	Department of Water Resources	AD
15	Pechanga Tribal Utility	Various	Pechanga Tribal Utility	OLF
16	City of Moreno Valley	Various	City of Moreno Valley	OLF
17	City of Vernon	Various	City of Vernon	AD
18	Pechanga Tribal Utility	Various	Pechange Tribal Utility	AD
19	City of Moreno Valley	Various	City of Moreno Valley	AD
20	High Desert Power Trust	Various	High Desert Power Trust	AD
21				
22	Rounding			
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
317	Rio Hondo	Goodrich				1
390.2	Mead	Vista	30			2
390.2	Mead	Vista	30			3
391.2	Victorville-Lugo	Vista	156			4
391.2	Victorville-Lugo	Vista	156			5
392.2	Victorville-Lugo	Vista	12			6
392.2	Victorville-Lugo	Vista	12			7
393.2	San Onofre	Vista	42			8
393.2	San Onofre	Vista	42			9
207.26	Mead	Laguna Bell	26			10
360.2	Victorville-Lugo	Laguna Bell	75			11
359.1	Laguna Bell	Vernon				12
373	Victorville-Lugo	Rio Hondo	4			13
373	Victorville-Lugo	Rio Hondo	4			14
372	Mead	Rio Hondo	4			15
372	Mead	Rio Hondo	4			16
374	Victorville-Lugo	Rio Hondo	14			17
374	Victorville-Lugo	Rio Hondo	14			18
375	Mead / Rio Hondo	Mead / Rio Hondo	8			19
375	Mead / Rio Hondo	Mead / Rio Hondo	8			20
376	Sylmar	Rio Hondo	10			21
362	Victorville-Lugo	Vista	3			22
362	Victorville-Lugo	Vista	3			23
361	Mead	Vista	3			24
361	Mead	Vista	3			25
363	Victorville-Lugo	Vista	18			26
363	Victorville-Lugo	Vista	18			27
365	Devers	Vista				28
365	Devers	Vista				29
364	IPC/Sylmar	Vista	3			30
379	Victorville-Lugo	Devers	3			31
379	Victorville-Lugo	Devers	3			32
378	Mead	Devers	2			33
378	Mead	Devers	2			34
			5,481	**8,473,018**	**8,426,133**	

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
381	Devers	Devers	15			1
381	Devers	Devers	15			2
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo	5			3
380	Victorvle-Lugo-Ban	Ban / Victorvle-Lugo	5			4
113	El Dorado	Vincent	235			5
112.3	Devil Canyon	Calectric	120			6
342	Mohave	Vincent	28			7
402	Cool Water	Kramer				8
401	Mandalay	Santa Clara				9
404	Ormond Beach	Moorpark				10
403	Huntington Beach	Ellis				11
Vol. 6, SA #11	Victor Substation	High Desert				12
470	Valley Sub	Inlnd Empr Enrgy Ctr				13
Vol. 6, SA #35	Bailey-Oso	Various	17			14
Vol. 6, SA #34	Pastoria-Pardee	Various	82			15
Vol. 6, SA #31	Edmonston-Pastoria	Vincent	787			16
Vol. 6, SA #32	Vincent	Various	152			17
Vol. 6, SA #33	Bailey-Sub	Various	72			18
443	Vincent	Julian Hinds				19
219	Various	Various	368			20
219	Various	Various	368			21
131	Mead	Mountain Center	10			22
349.8	Various	Various				23
339	Victorville-Lugo	Midway	150			24
Vol. 5, SA #2	Rio Hondo	Azusa				25
Vol. 5, SA #5	Vista	Riverside City Limit		2,199,474	2,190,456	26
Vol. 5, SA #3	Near Devers	Banning		154,681	150,040	27
Vol. 5, SA #3	Near Devers	Banning				28
Vol. 5, SA #2	Rio Hondo	Azusa		203,591	200,110	29
Vol. 5, SA #2	Rio Hondo	Azusa				30
Vol. 5, SA #1	Vista	City of Colton		585,041	582,468	31
Vol. 5, SA #1	Vista	City of Colton				32
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39	146,524	141,088	33
Vol. 5, SA #4	Victor and Vista Sub	Cttnwood & Zanja Sub	39			34
			5,481	**8,473,018**	**8,426,133**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.				1
Vol. 5, SA #48	Walnut Sub 230 kV Bs	Indstry-Old Rnch Rd.				2
Vol. 5, SA #77	Mira Loma	Crossings Bus. Ctr.		18,593	17,714	3
Vol. 5, SA #77	Mira Loma	Crossings Bus. Ctr.				4
Vol. 5, SA #56	Vista	Cherry Valley Stn		1,055	985	5
Vol. 5, SA #56	Vista	Cherry Valley Stn				6
Vol. 5, SA #57	Vista	Crafton Hills Stn		19,860	19,703	7
Vol. 5, SA #57	Vista	Crafton Hills Stn				8
Vol. 5, SA #58	San Bernardino	Greenspot Station	4	708	696	9
Vol. 5, SA #58	San Bernardino	Greenspot Station	4			10
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn		78,032	77,477	11
Vol. 5, SA #89	Etiwanda	Cty of Rncho Cucamn				12
Vol. 5,SA #130	Mira Loma	Cleargen Sub		13,658	13,515	13
Vol. 5,SA #130	Mira Loma	Cleargen Sub				14
Vol. 5,SA #97	Mira Loma	Corona Pointe		21,368	20,736	15
Vol. 5,SA #97	Mira Loma	Corona Pointe				16
Vol. 5,SA #103	Valley Sub	Moreno Valley		6,628	6,517	17
Vol. 5,SA #103	Valley Sub	Moreno Valley				18
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1	26,059	24,330	19
Vol. 5,SA #125	Mira Loma	Corona Dos Lagos	1			20
Vol. 5,SA #115	Valley Sub	Moreno Valley		17,410	17,096	21
Vol. 5,SA #115	Valley Sub	Moreno Valley				22
Vol. 5,SA #117	Valley Sub	Moreno Valley	1	2,336	2,301	23
Vol. 5,SA #117	Valley Sub	Moreno Valley	1			24
Vol. 5,SA #143	Valley Sub	Moreno Valley	1	569	554	25
Vol. 5,SA #143	Valley Sub	Moreno Valley	1			26
Vol. 5,SA #128	Valley Sub	Moreno Valley		7,976	7,805	27
Vol. 5,SA #128	Valley Sub	Moreno Valley				28
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Way	2			29
Vol. 5,SA #152	Chino Sub,220kV Bus	Indstry/Wddghm Wa	2			30
Vol. 5,SA #149	Valley Sub	Moreno Valley	12	64,568	64,290	31
Vol. 5,SA #149	Valley Sub	Moreno Valley	12			32
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2	1,703	1,683	33
Vol. 5,SA #165	Walnut Sub,220kV bus	IndstryAnheimPuente	2			34
			5,481	**8,473,018**	**8,426,133**	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. 5,SA #179	Mountain Center	Anza	1	63,247	58,301	1
Vol. 5,SA #179	Mountain Center	Anza	1			2
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1	15,731	15,333	3
Vol. 5,SA #151	Mira Loma	Corona Sunkist	1			4
Vol. 5,SA #193	Various	Various		28,993	27,601	5
Vol. 5,SA #193	Various	Various				6
Vol. 5,SA #218	Victor Sub	City of Victorville		21,172	20,544	7
Vol. 5,SA #218	Victor Sub	City of Victorville				8
Vol. 5,SA #231	Victor Sub	City of Victorville		83,529	78,032	9
Vol. 5,SA #231	Victor Sub	City of Victorville				10
Vol. 5,SA #695	Valley Sub	Moreno Valley	1	2,706	2,645	11
Vol. 5,SA #695	Valley Sub	Moreno Valley	1			12
361,362,363,3	Various	Various				13
Vol. 6, SA#33	Bailey-Oso	Edmnstn Pmpng Plant	72	1,977,653	1,977,653	14
Vol. 6, SA#33	Bailey-Oso	Edmnstn Pmpng Plant	72	1,142,850	1,142,850	15
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant	152	337,951	337,951	16
Vol. 6, SA#32	Edmonston-Pastoria	Pearblssm Pmpg Plant	152	239,608	239,608	17
Vol. 6, SA#31	Vincent	Oso Pumping Plant	787	86,161	86,161	18
Vol. 6, SA#31	Vincent	Oso Pumping Plant	787	32,333	32,333	19
131	Mead	Mountain Center	10			20
131	Mead	Mountain Center	10			21
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	103,839	103,839	22
Vol. 5, SA #4	Victor and Vista Sub	Cottnwood&Zanja Sub	39	39,156	39,156	23
Vol. No. 5	Various	Various		22,207	22,207	24
Vol. No. 5	Various	Various		7,178	7,178	25
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		69,716	69,716	26
Vol. 5, SA #77	Mira Loma	Temescal P.T. Sub		22,191	22,191	27
Vol.	Various	Various		33,566	33,566	28
Vol.	Various	Various		15,983	15,983	29
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		59,604	59,604	30
Vol. 5, SA #89	Etiwanda Sub	Arbors Sub		18,063	18,063	31
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	148,673	148,673	32
Vol. 5,SA #103	Valley Sub	Moreno Vly Iris Ave	3	49,757	49,757	33
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct		80,216	80,216	34
			5,481	**8,473,018**	**8,426,133**	

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

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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Vol. No. 6	Victor Sub	Victrvil 12kV Intrct		24,211	24,211	1
Vol. No. 6	Victor Sub	SCE'sCement33kV line				2
Vol. No. 6	Victor Sub	SCE'sCement33kV line				3
N/A	N/A	N/A				4
N/A	N/A	N/A				5
489.1.0	Sunlot	Kramer				6
Vol.5, SA #737	Walnut Sub	Puente Sub		7,856	7,693	7
Vol.5, SA #737	Walnut Sub	Puente Sub				8
131	Mead	Mountain Center	10			9
Vol.5, SA #5	Vista	RiversideCityLimits				10
Vol.5, SA #240	Chino Sub	GrandCrossingSub	7	21,424	20,982	11
Vol.5, SA #240	Chino Sub	GrandCrossingSub	7			12
Vol.5, SA #874	El Caso Sub	ClementineMentonePrw	2	24,986	24,567	13
Vol.5, SA #874	El Caso Sub	ClementineMentonePrw	2			14
Vol.5, SA #977	Valley Sub	12Kv@GreatOakPoletop				15
Vol.5, SA #972	Valley Sub	Kitching Street	15	100,121	98,688	16
207.26	Mead	Laguna Bell	26			17
Vol.5,SA #977	Valley Sub	Located at Great Oak		22,504	21,268	18
Vol.5,SA #972	Valley Sub	Kitching Street	15			19
Vol.6,SA #11	Victor Substation	High Desert				20
						21
				-1	-1	22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			5,481	**8,473,018**	**8,426,133**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
2,217,600			2,217,600	2
				3
11,531,520			11,531,520	4
				5
887,040			887,040	6
				7
				8
				9
1,921,920			1,921,920	10
813,120			813,120	11
265,776		30,252	296,028	12
295,680			295,680	13
				14
				15
				16
				17
				18
				19
				20
				21
221,760			221,760	22
				23
				24
				25
				26
				27
				28
				29
				30
221,760			221,760	31
				32
				33
				34
92,054,243	**0**	**18,308,402**	**110,362,645**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
				3
				4
				5
46,800			46,800	6
151,200			151,200	7
		9,727	9,727	8
		209,706	209,706	9
		651,331	651,331	10
		402,148	402,148	11
		235,987	235,987	12
		42,492	42,492	13
		35,472	35,472	14
		41,172	41,172	15
		93,972	93,972	16
		267,600	267,600	17
		71,400	71,400	18
				19
13,601,280		13,601,280	27,202,560	20
				21
				22
194,947			194,947	23
				24
		125,331	125,331	25
16,104		1,281,759	1,297,863	26
286,611		993,069	1,279,680	27
25,760		90,279	116,039	28
155,696		51,472	207,168	29
14,123		4,679	18,802	30
286,251		31,815	318,066	31
18,956		2,892	21,848	32
605,147		159	605,306	33
56,969		14	56,983	34
92,054,243	**0**	**18,308,402**	**110,362,645**	

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

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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
75,212		86,836	162,048	3
8,751		5,260	14,011	4
50,845		75	50,920	5
2,450		9	2,459	6
714,551		459	715,010	7
20,139		9	20,148	8
305,800		103	305,903	9
27,800		9	27,809	10
25,247		107	25,354	11
1,942		10	1,952	12
13,465		84	13,549	13
1,184		8	1,192	14
49,358		889	50,247	15
3,905		81	3,986	16
28,819		79	28,898	17
2,618		7	2,625	18
68,192		79	68,271	19
4,592		7	4,599	20
79,003		84	79,087	21
6,944		8	6,952	22
37,105		84	37,189	23
7,071		8	7,079	24
30,696		80	30,776	25
4,448		7	4,455	26
37,336		84	37,420	27
2,939		8	2,947	28
				29
				30
131,460		80	131,540	31
10,440		7	10,447	32
11,220		82	11,302	33
1,020		7	1,027	34
92,054,243	**0**	**18,308,402**	**110,362,645**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
453,845		80	453,925	1
37,380		7	37,387	2
31,099		80	31,179	3
2,678		7	2,685	4
177,408		4,613	182,021	5
16,128		419	16,547	6
75,900		80	75,980	7
6,900		7	6,907	8
146,300		80	146,380	9
13,300		7	13,307	10
21,340		74	21,414	11
2,747		7	2,754	12
				13
		98,883	98,883	14
		57,143	57,143	15
		16,898	16,898	16
		11,980	11,980	17
		4,308	4,308	18
		1,617	1,617	19
				20
				21
		12,461	12,461	22
		7,301	7,301	23
		2,887	2,887	24
		933	933	25
		9,063	9,063	26
		2,885	2,885	27
		1,678	1,678	28
		799	799	29
		7,749	7,749	30
		2,348	2,348	31
		19,327	19,327	32
		6,468	6,468	33
		10,428	10,428	34
92,054,243	**0**	**18,308,402**	**110,362,645**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		4,195	4,195	1
				2
				3
53,992,548			53,992,548	4
152,000			152,000	5
		352,728	352,728	6
20,394		74	20,468	7
1,854		7	1,861	8
				9
1,342		106,813	108,155	10
84,629		74	84,703	11
14,491		7	14,498	12
353,980		82	354,062	13
34,560		7	34,567	14
434,313		88,911	523,224	15
172,584		77	172,661	16
147,160			147,160	17
39,483		8,083	47,566	18
19,305		10	19,315	19
		-901,944	-901,944	20
				21
3		3	6	22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
92,054,243	**0**	**18,308,402**	**110,362,645**	

Schedule Page: 328 Line No.: 1 Column: h
Billing Demand N/A
Schedule Page: 328 Line No.: 1 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 2 Column: d
OLF - 180 Days Notice
Schedule Page: 328 Line No.: 2 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 3 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 4 Column: d
OLF - 180 Days Notice
Schedule Page: 328 Line No.: 4 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 5 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 6 Column: d
OLF - 180 Days Notice
Schedule Page: 328 Line No.: 6 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 7 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 8 Column: d
OLF - 180 Days Notice
Schedule Page: 328 Line No.: 8 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 9 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 10 Column: d
OLF - Hoover PSC
Schedule Page: 328 Line No.: 10 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 11 Column: d
OLF - 12/31/02 / Perm. removed from service
Schedule Page: 328 Line No.: 11 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 12 Column: d
OLF - 2 Years Notice
Schedule Page: 328 Line No.: 12 Column: h
Billing Demand N/A
Schedule Page: 328 Line No.: 12 Column: m
Interconnection Service Charges.
Schedule Page: 328 Line No.: 13 Column: d
OLF - 1 Year Notice
Schedule Page: 328 Line No.: 13 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 14 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 15 Column: d
OLF - 1 Year Notice
Schedule Page: 328 Line No.: 15 Column: m

Customer charge per agreement.

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

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 17 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 17 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 18 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 19 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 19 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 20 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 21 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 22 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 22 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 23 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 24 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 24 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 25 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 26 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 26 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 27 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 28 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 28 Column: h

Billing Demand 14.04

Schedule Page: 328 Line No.: 28 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 29 Column: h

Billing Demand 14.04

Schedule Page: 328 Line No.: 29 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 30 Column: m

Revenue received in current year for prior year's service period.

Schedule Page: 328 Line No.: 31 Column: d

OLF - 1 Year Notice

Schedule Page: 328 Line No.: 31 Column: m

Customer charge per agreement.

Schedule Page: 328 Line No.: 32 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328 Line No.: 33 Column: d
OLF - 1 Year Notice
Schedule Page: 328 Line No.: 33 Column: m
Customer charge per agreement.
Schedule Page: 328 Line No.: 34 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328.1 Line No.: 1 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 1 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 2 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328.1 Line No.: 3 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 3 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 4 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328.1 Line No.: 5 Column: d
OLF - 12/31/20
Schedule Page: 328.1 Line No.: 5 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 6 Column: d
OLF - Plant Life
Schedule Page: 328.1 Line No.: 6 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 7 Column: d
OLF - Plant Life
Schedule Page: 328.1 Line No.: 7 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 8 Column: d
OLF - 12/31/23 / Take Serv
Schedule Page: 328.1 Line No.: 8 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 8 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.
Schedule Page: 328.1 Line No.: 9 Column: d
OLF - 12/31/04 / Take Serv
Schedule Page: 328.1 Line No.: 9 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 9 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.
Schedule Page: 328.1 Line No.: 10 Column: d
OLF - 12/31/07 / Take Serv
Schedule Page: 328.1 Line No.: 10 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 10 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.
Schedule Page: 328.1 Line No.: 11 Column: d
OLF - 12/31/03 / Cust. Termin.

Schedule Page: 328.1 Line No.: 11 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 11 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.
Schedule Page: 328.1 Line No.: 12 Column: d
OLF - 30 Days Notice
Schedule Page: 328.1 Line No.: 12 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 12 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: 328.1 Line No.: 13 Column: d
OLF - 30 Days Notice
Schedule Page: 328.1 Line No.: 13 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 13 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: 328.1 Line No.: 14 Column: d
OLF - 1/1/2035
Schedule Page: 328.1 Line No.: 14 Column: m
Interconnection service charges.
Schedule Page: 328.1 Line No.: 15 Column: d
OLF - 1/1/2035
Schedule Page: 328.1 Line No.: 15 Column: m
Interconnection service charges.
Schedule Page: 328.1 Line No.: 16 Column: d
OLF - 1/1/2035
Schedule Page: 328.1 Line No.: 16 Column: m
Interconnection service charges.
Schedule Page: 328.1 Line No.: 17 Column: d
OLF - 1/1/2035
Schedule Page: 328.1 Line No.: 17 Column: m
Interconnection service charges.
Schedule Page: 328.1 Line No.: 18 Column: d
OLF - 1/1/2035
Schedule Page: 328.1 Line No.: 18 Column: m
Interconnection service charges.
Schedule Page: 328.1 Line No.: 19 Column: d
OLF - 9/30/17
Schedule Page: 328.1 Line No.: 19 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 19 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 20 Column: d
OLF - Term. Service
Schedule Page: 328.1 Line No.: 20 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 21 Column: m
Revenue received in current year for prior year's service period.
Schedule Page: 328.1 Line No.: 22 Column: d
OLF - 10 Year Notice

Schedule Page: 328.1 Line No.: 22 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 23 Column: d
OLF - 2 Year Notice
Schedule Page: 328.1 Line No.: 23 Column: h
Billing Demand 34/5
Schedule Page: 328.1 Line No.: 23 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 24 Column: d
OLF - 5 Year Notice
Schedule Page: 328.1 Line No.: 24 Column: m
Customer charge per agreement.
Schedule Page: 328.1 Line No.: 25 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 25 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 25 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 26 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 26 Column: h
Billing Demand N/A
Schedule Page: 328.1 Line No.: 26 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 27 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 27 Column: h
Billing Demand 36.40
Schedule Page: 328.1 Line No.: 27 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 28 Column: h
Billing Demand 36.40
Schedule Page: 328.1 Line No.: 28 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.: 29 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 29 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 29 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 30 Column: h
Billing Demand 48.70
Schedule Page: 328.1 Line No.: 30 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.: 31 Column: d
OLF - 1 Year Notice
Schedule Page: 328.1 Line No.: 31 Column: h
Billing Demand 67.70
Schedule Page: 328.1 Line No.: 31 Column: m
Customer charge plus facility charge per agreement.
Schedule Page: 328.1 Line No.: 32 Column: h

Billing Demand 67.70

Schedule Page: 328.1 Line No.: 32 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.: 33 Column: d

OLF - 1 Year Notice

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

Customer charge plus facility charge per agreement.

Schedule Page: 328.1 Line No.: 34 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 1 Column: d

OLF - 12/31/32

Schedule Page: 328.2 Line No.: 1 Column: h

Billing Demand 7.2

Schedule Page: 328.2 Line No.: 1 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 2 Column: h

Billing Demand 7.2

Schedule Page: 328.2 Line No.: 2 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 3 Column: d

OLF - 180 Days Notice

Schedule Page: 328.2 Line No.: 3 Column: h

Billing Demand 1.7

Schedule Page: 328.2 Line No.: 3 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 4 Column: h

Billing Demand 1.7

Schedule Page: 328.2 Line No.: 4 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

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

OLF - Plant Life

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

Billing Demand .5

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

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 6 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 6 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 7 Column: d

OLF - Plant Life

Schedule Page: 328.2 Line No.: 7 Column: h

Billing Demand 3.7

Schedule Page: 328.2 Line No.: 7 Column: m

Customer charge plus facility charge per agreement.

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

Billing Demand 3.7

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

OLF - Plant Life

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

Customer charge plus facility charge per agreement.

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

OLF - 7/21/53

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

Billing Demand 3.867

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

Customer charge plus facility charge per agreement.

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

Billing Demand 3.867

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

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

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

OLF - 11/12/34

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

Billing Demand 2.5

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

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 14 Column: h

Billing Demand 2.5

Schedule Page: 328.2 Line No.: 14 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 15 Column: d

OLF - 180 Days Notice

Schedule Page: 328.2 Line No.: 15 Column: h

Billing Demand 3.28

Schedule Page: 328.2 Line No.: 15 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 16 Column: h

Billing Demand 3.28

Schedule Page: 328.2 Line No.: 16 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 17 Column: d

OLF - 04/11/2034

Schedule Page: 328.2 Line No.: 17 Column: h

Billing Demand 1.4

Schedule Page: 328.2 Line No.: 17 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 18 Column: h

Billing Demand 1.4

Schedule Page: 328.2 Line No.: 18 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 19 Column: d

OLF - 5/1/34

Schedule Page: 328.2 Line No.: 19 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 20 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 21 Column: d

OLF - 10/1/34

Schedule Page: 328.2 Line No.: 21 Column: h

Billing Demand 1.5

Schedule Page: 328.2 Line No.: 21 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 22 Column: h

Billing Demand 1.5

Schedule Page: 328.2 Line No.: 22 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 23 Column: d

OLF - 10/31/34

Schedule Page: 328.2 Line No.: 23 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 24 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 25 Column: d

OLF - 11/13/2035

Schedule Page: 328.2 Line No.: 25 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 26 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 27 Column: d

OLF - 03/5/35

Schedule Page: 328.2 Line No.: 27 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 27 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 28 Column: h

Billing Demand .5

Schedule Page: 328.2 Line No.: 28 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 29 Column: d

OLF - 10/03/36

Schedule Page: 328.2 Line No.: 29 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 30 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 31 Column: d

OLF - 07/22/37

Schedule Page: 328.2 Line No.: 31 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 32 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 33 Column: d

OLF - 5/3/37

Schedule Page: 328.2 Line No.: 33 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.2 Line No.: 34 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 1 Column: d

OLF - 6/1/38

Schedule Page: 328.3 Line No.: 1 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 2 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 3 Column: d

OLF - 6/17/36

Schedule Page: 328.3 Line No.: 3 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 4 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 5 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 5 Column: h

Billing Demand 6.5 / 1.5 / 0.7

Schedule Page: 328.3 Line No.: 5 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 6 Column: h

Billing Demand 6.5 / 1.5 / 0.7

Schedule Page: 328.3 Line No.: 6 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 7 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 7 Column: h

Billing Demand 4.5

Schedule Page: 328.3 Line No.: 7 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 8 Column: h

Billing Demand 4.5

Schedule Page: 328.3 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: 328.3 Line No.: 9 Column: d

OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 9 Column: h

Billing Demand 1.25

Schedule Page: 328.3 Line No.: 9 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 10 Column: h

Billing Demand 1.25

Schedule Page: 328.3 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: 328.3 Line No.: 11 Column: d

OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 11 Column: m

Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 12 Column: m

Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.3 Line No.: 13 Column: d

OLF - 1 Year Notice

Schedule Page: 328.3 Line No.: 13 Column: h

Billing Demand N/A

Schedule Page: 328.3 Line No.: 13 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 14 Column: d

OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 14 Column: m

Reliability Services Charge.

Schedule Page: 328.3 Line No.: 15 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 16 Column: d
OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 16 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 17 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 18 Column: d
OLF - 1/1/2035

Schedule Page: 328.3 Line No.: 18 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 19 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 20 Column: d
OLF - Upon Notice

Schedule Page: 328.3 Line No.: 20 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 21 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 22 Column: d
OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 22 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 23 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 24 Column: d
OLF - 180 Days Notice

Schedule Page: 328.3 Line No.: 24 Column: h
Billing Demand 7.2 / 2 / 2

Schedule Page: 328.3 Line No.: 24 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 25 Column: h
Billing Demand 7.2 / 2 / 2

Schedule Page: 328.3 Line No.: 25 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 26 Column: d
OLF - 30 Days Notice

Schedule Page: 328.3 Line No.: 26 Column: h
Billing Demand 1.7

Schedule Page: 328.3 Line No.: 26 Column: m
Reliability Services Charge.

Schedule Page: 328.3 Line No.: 27 Column: h
Billing Demand 1.7

Schedule Page: 328.3 Line No.: 27 Column: m
Reliability Service revenue received in current year for prior year's service.

Schedule Page: 328.3 Line No.: 28 Column: d
OLF - Plant Life

Schedule Page: 328.3 Line No.: 28 Column: h
Billing Demand .5

Schedule Page: 328.3 Line No.: 28 Column: m
Reliability Services Charge.
Schedule Page: 328.3 Line No.: 29 Column: h
Billing Demand .5
Schedule Page: 328.3 Line No.: 29 Column: m
Reliability Service revenue received in current year for prior year's service.
Schedule Page: 328.3 Line No.: 30 Column: d
OLF - 30 Days Notice
Schedule Page: 328.3 Line No.: 30 Column: h
Billing Demand 3.87
Schedule Page: 328.3 Line No.: 30 Column: m
Reliability Services Charge.
Schedule Page: 328.3 Line No.: 31 Column: h
Billing Demand 3.87
Schedule Page: 328.3 Line No.: 31 Column: m
Reliability Service revenue received in current year for prior year's service.
Schedule Page: 328.3 Line No.: 32 Column: d
OLF - 4/11/2034
Schedule Page: 328.3 Line No.: 32 Column: m
Reliability Services Charge.
Schedule Page: 328.3 Line No.: 33 Column: m
Reliability Service revenue received in current year for prior year's service.
Schedule Page: 328.3 Line No.: 34 Column: d
OLF - 180 Days Notice
Schedule Page: 328.3 Line No.: 34 Column: h
Billing Demand 5.6
Schedule Page: 328.3 Line No.: 34 Column: m
Reliability Services Charge.
Schedule Page: 328.4 Line No.: 1 Column: h
Billing Demand 5.6
Schedule Page: 328.4 Line No.: 1 Column: m
Reliability Service revenue received in current year for prior year's service.
Schedule Page: 328.4 Line No.: 2 Column: d
OLF - 180 Days Notice
Schedule Page: 328.4 Line No.: 2 Column: h
Billing Demand 1.25
Schedule Page: 328.4 Line No.: 2 Column: m
Reliability Services Charge.
Schedule Page: 328.4 Line No.: 3 Column: h
Billing Demand 1.25
Schedule Page: 328.4 Line No.: 3 Column: m
Reliability Service revenue received in current year for prior year's service.
Schedule Page: 328.4 Line No.: 4 Column: d
OS - Plant Life
Schedule Page: 328.4 Line No.: 4 Column: h
Billing Demand N/A
Schedule Page: 328.4 Line No.: 4 Column: m
Edison's share of statewide wheeling collected by the CAISO from scheduling coordinators.
Schedule Page: 328.4 Line No.: 5 Column: h
Billing Demand N/A
Schedule Page: 328.4 Line No.: 6 Column: d

OLF - 02/08/2012 / Cust. Termin.

Schedule Page: 328.4 Line No.: 6 Column: h
Billing Demand N/A

Schedule Page: 328.4 Line No.: 6 Column: m
Monthly Operating & Maintenance and base cost charge per radial lines agreement.

Schedule Page: 328.4 Line No.: 7 Column: d
OLF - 12/17/34

Schedule Page: 328.4 Line No.: 7 Column: h
Billing Demand 1.8

Schedule Page: 328.4 Line No.: 7 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 8 Column: h
Billing Demand 1.8

Schedule Page: 328.4 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: 328.4 Line No.: 9 Column: m
Revenue received in current year for prior year's service period.

Schedule Page: 328.4 Line No.: 10 Column: h
Billing Demand N/A

Schedule Page: 328.4 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: 328.4 Line No.: 11 Column: d
OLF - 9/10/45

Schedule Page: 328.4 Line No.: 11 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 12 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 13 Column: d
OLF - Plant Life

Schedule Page: 328.4 Line No.: 13 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 14 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 15 Column: d
OLF - 10/01/2047

Schedule Page: 328.4 Line No.: 15 Column: h
Billing Demand 16.05

Schedule Page: 328.4 Line No.: 15 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 16 Column: d
OLF - 11/17/2047

Schedule Page: 328.4 Line No.: 16 Column: m
Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 17 Column: m
Customer charge per agreement. Revenue received in current year for prior year's service period.

Schedule Page: 328.4 Line No.: 18 Column: h
Billing Demand 16.05

Schedule Page: 328.4 Line No.: 18 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 19 Column: m
Revenue received in current year for prior year's service period. Customer charge plus facility charge per agreement.

Schedule Page: 328.4 Line No.: 20 Column: h

Billing Demand N/A

Schedule Page: 328.4 Line No.: 20 Column: m

Edison's share of statewide congestion charges collected by the CAISO for congestion in the Edison control area caused by scheduling coordinators.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1	NONE.				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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27					
28					
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31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	OLF					-9,783	-9,783
2	WAPA Blythe	OLF					118,008	118,008
3	WAPA Mead/Parker	OLF					164,322	164,322
4	Imp Irrig Dist Salt Sea	LFP					-42,458	-42,458
5	Arizona Pub Serv (APS)	FNS						
6	Bonneville Power Admin	FNS	6,394,813	6,394,813		-115		-115
7	Nevada Power Company	FNS	492	492		15,537,508		15,537,508
8	PacifiCorp	FNS	745,482	745,482		443		443
9	WAPA - Desert SW Region	FNS	14,747	14,747		1,925,666		1,925,666
10	Portland General Elect	FNS				30,951		30,951
11						125		125
12								
13	Rounding					1		1
14								
15								
16								
	TOTAL		7,155,534	7,155,534		17,494,579	230,089	17,724,668

Schedule Page: 332 Line No.: 1 Column: b
OLF – 1 Year Notice
Schedule Page: 332 Line No.: 1 Column: g
(1) Includes APS O&M Charges.
Schedule Page: 332 Line No.: 2 Column: a
Western Area Power Administration (Western) -Blythe
Schedule Page: 332 Line No.: 2 Column: b
OLF - 1 Year Notice
Schedule Page: 332 Line No.: 2 Column: g
(2) Blythe O&M and Common Use fee charge to SCE.
Schedule Page: 332 Line No.: 3 Column: a
Western Area Power Administration (Western) -Mead/Parker
Schedule Page: 332 Line No.: 3 Column: b
OLF - 1 Year Notice
Schedule Page: 332 Line No.: 3 Column: g
(3) Common facilities Operation and Maintenance Charges.
Schedule Page: 332 Line No.: 4 Column: a
Imperial Irrigation Dist. (Salton Sea)
Schedule Page: 332 Line No.: 4 Column: g
(4) Transmission Service Charge to SCE (Contract 10036).
Schedule Page: 332 Line No.: 5 Column: a
Arizona Public Service Company (APS)
Schedule Page: 332 Line No.: 6 Column: a
Bonneville Power Administration
Schedule Page: 332 Line No.: 9 Column: a
Western Area Power Administration-Desert SW Region
Schedule Page: 332 Line No.: 10 Column: a
Portland General Electric Company

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	2,098,640
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	13,353,811
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	652,121
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Credit Line/Bank Charges	3,987,169
7	Director Fees	3,393,013
8	SEC Reports	508,761
9	Plan & Dev of Com Sys	1,704,316
10	Provision for Doubtful Accounts-Non-Energy Billings	-760,529
11	Vendor Discounts	-14,286,012
12	Accounting Suspense	-413,522
13	Miscellaneous	1,892,827
14		
15		
16	Admin and Gen by Other	11,760,166
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
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44		
45		
46	TOTAL	23,890,761

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			205,114,641		205,114,641
2	Steam Production Plant	3,970				3,970
3	Nuclear Production Plant	12,862,570			2,693,820	15,556,390
4	Hydraulic Production Plant-Conventional	34,021,992				34,021,992
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	64,847,618				64,847,618
7	Transmission Plant	350,201,587			87,299	350,288,886
8	Distribution Plant	940,610,730			5,259,834	945,870,564
9	Regional Transmission and Market Operation				19,737	19,737
10	General Plant	243,387,703				243,387,703
11	Common Plant-Electric	32,498				32,498
12	TOTAL	1,645,968,668		205,114,641	8,060,690	1,859,143,999

B. Basis for Amortization Charges

The basis used to compute the charges is the ending plant balance. The basis is different from the preceding year due to net plant additions throughout the year.

Account 404
The amortization of Intangible Plant is based on the following:

Capsoft and other misc.: Based on the anticipated useful life
Hydro Relicensing: 2.52%
Radio Frequency: 2.50%
Other Intangibles: 5.00%

Account 405
The amortization of the SUNK costs for Palo Verde Plant based on the end of life as authorized by Utility Retained Generation Decision 04-04-016.
The amortization of the Beyond the Meter Costs for Distribution basedon a 10 year life as authorized by Decision 14-03-021.

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PRODUCTION						
13	310.2	190				Life Span	
14	311		45.00			Life Span	
15	312		45.00			Life Span	
16	314		45.00			Life Span	
17	315		45.00			Life Span	
18	316		45.00			Life Span	
19							
20							
21	NUCLEAR PRODUCTION						
22	PVNGS 1,2 & 3						
23	320.2		34.00			License	29.50
24	321	214,702	34.00		0.77	License	29.50
25	322	137,483	34.00		0.51	License	29.50
26	323	75,139	34.00		0.49	License	29.50
27	324	17,790	34.00		0.25	License	29.50
28	325	47,001	34.00		0.18	License	29.50
29							
30							
31	HYDRAULIC						
32	330.2	3,216	60.00		2.69	License	32.00
33	331	228,022	56.00	-7.30	2.24	License	35.60
34	332	597,247	65.00	-3.70	2.36	License	30.80
35	333	196,176	55.00	-5.60	2.38	License	32.40
36	334	218,569	40.00	-20.30	4.22	License	26.60
37	335	13,161	60.00	-7.20	2.48	License	33.60
38	336	20,586	44.00	-24.60	4.73	License	27.30
39							
40							
41	OTHER PRODUCTION						
42	340.2	527	31.00		2.91	Life Span	26.60
43	341	110,042	31.00		2.91	Life Span	26.60
44	342	16,537	31.00		2.55	Life Span	26.60
45	343	1,209,463	31.00		2.61	Life Span	26.60
46	344	127,557	31.00		3.00	Life Span	26.60
47	345	207,861	31.00		2.59	Life Span	26.60
48	346	115,622	31.00		2.88	Life Span	26.60
49							
50							

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION PLANT						
13	350.2	211,617	60.00		1.67	Judgement*	56.00
14	352	983,204	55.00	-35.00	2.53	S 3.0	39.80
15	353	6,061,941	45.00	-15.00	2.66	R 0.5	34.30
16	354	2,355,112	65.00	-60.00	2.30	R 5.0	41.90
17	355	1,500,196	50.00	-72.00	3.43	R 0.5	37.70
18	356	1,652,820	61.00	-80.00	2.63	R 3.0	35.50
19	357	271,487	55.00		1.73	R 3.0	35.60
20	358	399,339	40.00	-15.00	2.65	R2.5	25.20
21	359	195,497	60.00		1.52	SQ	40.50
22							
23	DISTRIBUTION PLANT						
24	360.2	59,756	60.00		1.67	Judgement*	56.00
25	361	696,502	42.00	-25.00	3.04	R2.5	25.10
26	362	2,727,819	45.00	-25.00	3.13	R 1.5	30.80
27	364	3,147,697	47.00	-210.00	7.04	L 0.5	34.70
28	365	1,842,856	45.00	-115.00	4.87	R 0.5	31.20
29	366	2,390,671	59.00	-30.00	2.22	R 3.0	40.70
30	367	6,487,394	45.00	-60.00	2.98	R 0.5	34.20
31	368	4,219,262	33.00	-20.00	3.93	R 1.0	20.80
32	369	1,494,351	45.00	-100.00	4.34	R 1.5	28.70
33	370	1,011,251	20.00	-5.00	5.30	R 3.0	14.20
34	371	12,373	20.00	-5.00	5.30	R 3.0	14.20
35	373	862,112	40.00	-30.00	3.10	L 0.5	26.50
36							
37							
38	GENERAL						
39	389.2	3,282	60.00		1.67	Judgement*	57.00
40	390	1,079,838	38.00	-10.00	2.74	R 3.0	24.80
41	391.XXX	773,381	12.00		16.48	Judgement*	4.30
42	392.4		7.00		14.29	Judgement*	4.00
43	393	10,858	20.00		5.00	Judgement*	17.00
44	394.6		10.00		10.00	Judgement*	7.00
45	395	118,526	15.00		6.67	Judgement*	12.00
46	396	789	15.00	25.00	6.67	Judgement*	12.00
47	397	910,459	16.00		9.77	Judgement*	13.20
48	398	45,514	20.00		5.00	Judgement*	
49							
50	TOTAL	45,082,795					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Regulatory Commission Assessed Expenses				
2	CPUC Applications - Various				
3	FERC Order No. 472				
4	Intervenor Compensation				
5	Outside Legal Svcs & Related Expenses				
6					
7	NO DOCKET		18,309	18,309	
8	TRANSCRIPTS -CPUC (ONLY)				
9	LA1990000067				
10					
11	EL00-95-000, EL00-98-000		1,982,008	1,982,008	
12	FERC INVESTIGATION				
13	LA2000000853				
14					
15	RM07-01		1,397	1,397	
16	SOC AND OTHER FERC COMPLIANCE MATTERS				
17	LA2004000567				
18					
19	NO DOCKET		3,370	3,370	
20	SAN FRANCISCO OFFICE LA2004001099				
21					
22	07-157C, 07-167C		46,554	46,554	
23	CALIFORNIA MUNI LITIGATION				
24	LA2006000235				
25					
26	A.06-08-011, D.07-03-013, EL11-8, EL11-11, AD		14,433	14,433	
27	16-20, RM16-23				
28	ISO/TO/RTO/VARIOUS TRANS & MKT ISSUES				
29	LA2006000712				
30					
31	ER07-830, ER19-39, ER19-154		174	174	
32	ELDORADO CONTRACTS LA2007000417				
33					
34	R.11-09-011		50	50	
35	INTERCONNECTION ISSUES LA2008000697				
36					
37	A.08-07-021, D.09-09-047		48,613	48,613	
38	CEES - CUSTOMER ENERGY EFF & SOLAR GRP				
39	LA2010000646				
40					
41	A.16-09-001		34,503	34,503	
42	GENERAL RATE CASE				
43	LA2012000405				
44					
45					
46	TOTAL	7,416,697	4,308,387	11,725,084	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	I.12-10-013 et al.		1,966,388	1,966,388	
2	SONGS OII LA2012002218				
3					
4	R.18-07-003, R.15-02-020, EL13-71, EL15-52,		2,148	2,148	
5	QF13-403				
6	WINDING CREEK SOLAR ENFORCEMENT ACTION				
7	LA2013000342				
8					
9	NO DOCKET		2,808	2,808	
10	NUCLEAR FUEL TRADING AGREEMENTS				
11	LA2014000271				
12					
13	R.14-08-013 et al.		2,066	2,066	
14	DRP RELATED ISSUES				
15	LA2015000179				
16					
17	NO DOCKET		1,548	1,548	
18	ANTITRUST ADVICE LA2015000253				
19					
20	ER11-3697, ER18-169, EL18-44		30,934	30,934	
21	FORMULA RATE 2017				
22	LA2015000256				
23					
24	I.15-11-006		60,576	60,576	
25	HUNTINGTON BEACH VAULT EXPLOSION OII				
26	LA2015000427				
27					
28	C.16-10-021		623	623	
29	GILDRED CPUC COMPLAINT				
30	LA2016000493				
31					
32	I.15-11-006		60,576	60,576	
33	PAR (HUNTINGTON BEACH OII)				
34	LA2017000162				
35					
36	A.16-09-001		80,891	80,891	
37	GRC - POLES LA2017000234				
38					
39	A.16-09-001		14,661	14,661	
40	2018 GRC (E-DISCOVERY)				
41	LA2017000335				
42					
43	No Docket		-1,374	-1,374	
44	HALEY WORKPLACE VIOLENCE TRO				
45	LA2017000417				
46	TOTAL	7,416,697	4,308,387	11,725,084	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	A.13-03-013, A.13-03-014		46,285	46,285	
2	SONGS RSG REG/COMM LIT/INSUR (E-DISCOVER				
3	LA2017000440				
4					
5	C.16-10-021		9,611	9,611	
6	GILDRED CPUC COMPLAINT (E-DISCOVERY)				
7	LA2017000456				
8					
9	A.16-09-001		19,631	19,631	
10	T&D POLE ATTACHMENTS				
11	LA2017000466				
12					
13	A.15-09-010		55,001	55,001	
14	SDG&E WEMA APP FOR 2007 WILDFIRES				
15	LA2017000707				
16					
17	R.17-06-026		4,432	4,432	
18	PCIA OIR (E-DISCOVERY)				
19	LA2017000734				
20					
21	No Docket		133,333	133,333	
22	FIXED FEE AGMT-JENNIFER KEY (2018)				
23	LA2018000033				
24					
25	I.18-11-006		23,011	23,011	
26	RAMP FILING LA2018000385				
27					
28	A.18-09-002		166,121	166,121	
29	SCE GRID RESILIENCY BALANCING ACCT APP				
30	LA2018000399				
31					
32	A.16-09-001		2,469	2,469	
33	GRC - POLES (E-DISCOVERY)				
34	LA2018000560				
35					
36	No Docket		31,644	31,644	
37	FERC DATA PRESERVATION REQUEST RE OUTAGE				
38	LA2018000609				
39					
40	No Docket		1,859	1,859	
41	FERC DATA PRESERVATION REQ (E-DISCOVERY)				
42	LA2018000729				
43					
44	YEAR END ACCRUALS		-556,345	-556,345	
45	PROCUREMENT/EQUIPTMENT SERVICES		79	79	
46	TOTAL	7,416,697	4,308,387	11,725,084	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	REGULATORY COMMISSION EXPENSES:				
2	ISO FERC FEES - Corporate & Regulatory Acctng	5,656,224		5,656,224	
3	INTERVENOR COMPENSATION	1,760,472		1,760,472	
4					
5	EMPLOYEES SALARIES AND EXPENSES RELATED				
6	TO FORMAL CASES:				
7	FERC Applications				
8	Minor Items (Less than $25,000)				
9					
10	ROUNDING ADJUSTMENT	1		1	
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
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34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	7,416,697	4,308,387	11,725,084	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
							4
							5
							6
ELECTRIC	928	18,309					7
							8
							9
							10
ELECTRIC	928	1,982,008					11
							12
							13
							14
ELECTRIC	928	1,397					15
							16
							17
							18
ELECTRIC	928	3,370					19
							20
							21
ELECTRIC	928	46,554					22
							23
							24
							25
ELECTRIC	928	14,433					26
							27
							28
							29
							30
ELECTRIC	928	174					31
							32
							33
ELECTRIC	928	50					34
							35
							36
ELECTRIC	928	48,613					37
							38
							39
							40
ELECTRIC	928	34,503					41
							42
							43
							44
							45
		11,239,506					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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
ELECTRIC	928	1,966,388					1
							2
							3
ELECTRIC	928	2,148					4
							5
							6
							7
							8
ELECTRIC	928	2,808					9
							10
							11
							12
ELECTRIC	928	2,066					13
							14
							15
							16
ELECTRIC	928	1,548					17
							18
							19
ELECTRIC	928	30,934					20
							21
							22
							23
ELECTRIC	928	-425,000					24
							25
							26
							27
ELECTRIC	928	623					28
							29
							30
							31
ELECTRIC	928	60,576					32
							33
							34
							35
ELECTRIC	928	80,891					36
							37
							38
ELECTRIC	928	14,661					39
							40
							41
							42
ELECTRIC	928	-1,374					43
							44
							45
		11,239,506					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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
ELECTRIC	928	46,285					1
							2
							3
							4
ELECTRIC	928	9,611					5
							6
							7
							8
ELECTRIC	928	19,631					9
							10
							11
							12
ELECTRIC	928	55,001					13
							14
							15
							16
ELECTRIC	928	4,432					17
							18
							19
							20
ELECTRIC	928	133,333					21
							22
							23
							24
ELECTRIC	928	23,011					25
							26
							27
ELECTRIC	928	166,121					28
							29
							30
							31
ELECTRIC	928	2,469					32
							33
							34
							35
ELECTRIC	928	31,644					36
							37
							38
							39
ELECTRIC	928	1,859					40
							41
							42
							43
ELECTRIC	928	-556,345					44
ELECTRIC	928	79					45
		11,239,506					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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
ELECTRIC	928	5,656,224					2
ELECTRIC	928	1,760,472					3
							4
							5
							6
							7
							8
							9
		-1					10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
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							40
							41
							42
							43
							44
							45
		11,239,506					46

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
 (1) Generation
  a. hydroelectric
   i. Recreation fish and wildlife
   ii Other hydroelectric
  b. Fossil-fuel steam
  c. Internal combustion or gas turbine
  d. Nuclear
  e. Unconventional generation
  f. Siting and heat rejection
 (2) Transmission
  a. Overhead
  b. Underground
 (3) Distribution
 (4) Regional Transmission and Market Operation
 (5) Environment (other than equipment)
 (6) Other (Classify and include items in excess of $50,000.)
 (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
 (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. ENVIRONMENTAL HEALTH & SAFETY	
2		General Support Number for PEM Research
3		EPRI
4		
5	B. TRANSMISSION & DISTRIBUTION (T&D)	
6		GA-AVVC OF SCE'S TRANSMISSION SYS (O&M)
7		CLSD-GA-STATE ESTIMATION USING PMU (O&M)
8		GA-WIDE-AREA RELIABLTY MGMT & CTRL (O&M)
9		GA-BULK SYSTEM RESTORATION (O&M)
10		VERSATILE PLUG-IN AUX PWR SYS (O&M)
11		ES&T- DYNAMIC POWER CONDITIONER (O&M)
12		ES&T-OPTM CNTRL OF MULTI STRGE SYS (O&M)
13		EPIC II-SCE ADMINISTRATION (O&M)
14		GA-INTEGRATION OF BIG DATA (O&M)
15		CLSD-GA-INTEGRATED GRID PROJECT (O&M)
16		GA-SA3 PHASE III DEMONSTRATION (O&M)
17		GA-PROACTIVE STORM IMPACT ANALYSIS (O&M)
18		GA-ADVANCED GRID CAPABILITIES (O&M)
19		DYNAMIC PWR CONDITIONER (PMO)_(O&M)
20		NEXTGENDAII (O&M)
21		FAST_CHARGER_SYSTEM_IMPACT_DEMO (O&M)
22		SYSTEM_INTELLIGENCE_&_SA_CAPAB (O&M)
23		SYS_INTELLIGENCE_&_SA_CAPAB (PMO)_ (O&M)
24		IGP (II)_(O&M)
25		EASE (PMO)_(O&M)
26		EPIC-SCE ADMINISTRATION
27		CLSD-GA-REGIONAL GRID OPTIMIZATION
28		CLSD-ES&T-DISTRIBUTED OPTIMIZED STORAGE
29		GA-REG MANDATES: SUBMETERING DEMO
30		GA-SA3 PHASE III DEMONSTRATION
31		GA-BEYOND THE METER (PHASE II)
32		GA-NEXT GENERATION DA
33		GA-OUTAGE MANAGEMENT DEMO
34		GA-AVVC OF SCE'S TRANSMISSION SYSTEM
35		CLSD-GA-STATE ESTIMATION USING PMU
36		GA-WIDE-AREA RELIABILITY MGMT & CONTROL
37		ES&T-VERSATILE PLUG-IN AUX POWER SYS
38		ES&T- DYNAMIC POWER CONDITIONER

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	B. TRANSMISSION & DISTRIBUTION (T&D) Cont'd.	
2		ES&T - OPTIM CONTRL OF MULTI STORAGE SYS
3		EPIC II-SCE ADMINISTRATION
4		GA-SUBMETERING PHASE 2
5		GA-INTEGRATION OF BIG DATA
6		GA-PROACTIVE STORM IMPACT ANALYSIS
7		GA-ADVANCED GRID CAPABILITIES
8		ES&T-VERSATILE PLUG-IN AUX PWR SYS (PMO)
9		GA-PROACTIVE STORM IMPACT ANALYSIS (PMO)
10		NEXTGENDAII
11		FAST_CHARGER_SYSTEM_IMPACT_DEMO
12		SYSTEM_INTELLIGENCE_&_SA_CAPABILITIES
13		NEXTGENDAII (PMO)
14		FAST_CHARGER_SYSTEM_IMPACT_DEMO (PMO)
15		SYSTEM_INTELLIGENCE_&_SA_CAPABILI (PMO)
16		POWER_FLOW_W_TCSC (PMO)
17		IGP (II)
18		
19	TOTAL	
20		
21	C. CUSTOMER SERVICE / END USE	
22		18 ET T. Development Support-DI-Prgm
23		18 ET T. Assessment Support-DI-Prgm
24		18 ET T. Introduction Support-DI-Prgm
25		RP - Emerging Technology EE Program
26		DR2013 Technical Assistance & Audits-Pro
27		DR2013 Technical Assistance & Audits-Adm
28		DR13 IDSM TRIO/IDEA 365 Plt-Prg (613751)
29		DR12 EM&T Prog EP (612704)
30		DR09B EM&T Emerging Products (602596)
31		DR12 EM&T Admin SP Comm'l & Ind (612635)
32		DR2015 EM&T Program
33		DR2015 Tech Assist & Audits-Pro
34		DR2015 IDSM TRIO/IDEAA 365 Pilot-Program
35		DR2017 EM&T Program
36		DR2017 EM&T Admin Ext Rel
37		DR2017 IDSM TRIO/IDEAA 365 Pilot-Program
38		DR2017 IDSM TRIO/IDEAA 365 Pilot - Admin

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	C. CUSTOMER SERVICE / END USE cont'd.	
2		DR2017 Tech Assist & Audits-Program
3		DR2017Tech Assist&Audits-Adm Ext Rel
4		Engineering Svc-ET, Techn Test Cntr (DR)
5		DR2018 EM&T Program CP&S
6		DR2018 IDSM TA Program CP&S
7		18-22 DR Program Administration
8		18-22 DR Program G&A
9		18-22 DR Program G&A-Non Labor
10		RA DR Program
11		DSM Economic Analysis & Reporting DR G&A
12		DSM Program Operations DR G&A
13		DSM Portfolio Prfrmance & Metrics DR G&A
14		DSM Residential Prgm DR G&A
15		DSM Business Prgm DR G&A
16		DSM Prod Develpmnt & Div Mgmt DR G&A
17	TOTAL	
18		
19	D. INFORMATION TECHNOLOGY	
20		SCE CES21 - Physical Test Bed
21		SCE CES21-Indicator and Remediation Lang
22		SCE CES21#8 SCADA Ecosystem Resiliency
23		SCE CES21#8(labor) MMATR Ecosystem Resil
24		SCE CES21- MMATR Integration
25		SCE CES21- Project Management & Expenses
26	TOTAL	
27		
28	Research and Development A, B, C, D	
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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
		920A			2
		920A			3
					4
					5
	4,200	930C	4,200		6
515		930C	515		7
8,243	132	930C	8,375		8
701		930C	701		9
71,329			71,329		10
12,226	106	930C	12,331		11
77,320	33	930C	77,353		12
114,703		930C	114,703		13
10,027		930C	10,027		14
131		930C	131		15
407,069	16	930C	407,084		16
93,837		930C	93,837		17
8,379		930C	8,379		18
7,135		930C	7,135		19
591,119	1,092	930C	592,210		20
15,763		930C	15,763		21
73,337		930C	73,337		22
4,942		930C	4,942		23
1,195,354	32,536	930C	1,227,891		24
8,278		930C	8,278		25
403	11,226	930R	11,629		26
-17	28,411	930R	28,394		27
6,260		930R	6,260		28
69		930R	69		29
189,466	1,098,838	930R	1,288,304		30
1,699	14,400	930R	16,099		31
5,106	-116,247	930R	-111,141		32
292		930R	292		33
10,485	318,361	930R	328,846		34
-2		930R	-2		35
12,207	187,660	930R	199,867		36
7,759	134,840	930R	142,599		37
384	27,800	930R	28,184		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 Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
	137,395	930R	137,395		2
242,169	548,863	930R	791,032		3
44,474	338,934	930R	383,408		4
	391,909	930R	391,909		5
2,578	315,498	930R	318,076		6
970		930R	970		7
5,006		930R	5,006		8
9,616		930R	9,616		9
167,799	2,062,899	930R	2,230,698		10
250	4,847	930R	5,097		11
50,384	286,411	930R	336,795		12
36,989		930R	36,989		13
2,772		930R	2,772		14
-17		930R	-17		15
999	44,579	930R	45,577		16
144,794	3,823,744	930R	3,968,538		17
					18
3,643,302	9,698,483		13,341,782		19
					20
					21
1,308	889,743	908P	891,050		22
9,948	889,360	908P	899,308		23
1,308	886,733	908P	888,040		24
1,788,250	139,976	908P	1,928,226		25
-2,667		908D	-2,667		26
	-1	908D	-1		27
		908D			28
281	173,863	908D	174,145		29
191		908D	191		30
	63	908D	63		31
48,416	665,026	908D	713,442		32
	-94,008	908D	-94,008		33
	-105	908D	-105		34
161,705	1,276,555	908D	1,438,261		35
144		908D	144		36
	14	908D	14		37
6		908D	6		38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
2,667	94,097	908D	96,764		2
31		908D	31		3
-334	19	908D	-315		4
1,304	1,553,555	908P	1,554,859		5
	292,287	908P	292,287		6
1,847	590,900	908P	592,747		7
219,180	13,256	908P	232,437		8
	2,130	908P	2,130		9
4,184		908P	4,184		10
3		908P	3		11
-39	1	908P	-37		12
-1,224	-280	908P	-1,504		13
		908P			14
-51		908P	-51		15
-382	-14	908M	-395		16
2,236,076	7,373,170		9,609,249		17
					18
					19
		923R			20
	603,258	923R	603,258		21
2,149	1,140,812	923R	1,142,960		22
258,999	359,067	923R	618,067		23
	16,991	923R	16,991		24
237,455	5,057	923R	242,513		25
498,603	2,125,185		2,623,789		26
					27
6,377,983	19,196,837		25,574,821		28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	51,665,751		
4	Transmission	62,576,724		
5	Regional Market			
6	Distribution	148,225,051		
7	Customer Accounts	71,528,897		
8	Customer Service and Informational	73,652,630		
9	Sales	2,332,318		
10	Administrative and General	218,378,293		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	628,359,664		
12	Maintenance			
13	Production	17,791,914		
14	Transmission	14,608,619		
15	Regional Market			
16	Distribution	88,146,394		
17	Administrative and General	2,270,975		
18	TOTAL Maintenance (Total of lines 13 thru 17)	122,817,902		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	69,457,665		
21	Transmission (Enter Total of lines 4 and 14)	77,185,343		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	236,371,445		
24	Customer Accounts (Transcribe from line 7)	71,528,897		
25	Customer Service and Informational (Transcribe from line 8)	73,652,630		
26	Sales (Transcribe from line 9)	2,332,318		
27	Administrative and General (Enter Total of lines 10 and 17)	220,649,268		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	751,177,566		751,177,566
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	-17,928		
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution	171		
37	Customer Accounts	70,982		
38	Customer Service and Informational			
39	Sales			
40	Administrative and General	233,379		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	286,604		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply	144,540		
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	71,743		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	216,283		
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)	126,612		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	71,914		
58	Customer Accounts (Line 37)	70,982		
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	233,379		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	502,887		502,887
63	Other Utility Departments			
64	Operation and Maintenance	1,913,811		1,913,811
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	753,594,264		753,594,264
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	803,048,419		803,048,419
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	803,048,419		803,048,419
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	5,146,834		5,146,834
79	Nonutility Operations	8,859,021		8,859,021
80	Miscellaneous Other Accounts	35,448,883		35,448,883
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	49,454,738		49,454,738
96	TOTAL SALARIES AND WAGES	1,606,097,421		1,606,097,421

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	RETIREMENTS	BALANCE END OF YEAR
Structures and Improvements	$ 4,905,408	$ -	$(3,904,907)*	$ 1,000,501
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	5,020,891	-	(4,020,390)	1,000,501
Construction Work in Progress	-	-	-	-
Total Common Utility Plant	$ 5,020,891	$	$(4,020,390)	$ 1,000,501

*Footnote: $3,904,907 transferred to Catalina Electric. Shown as Retirements instead of negative adds.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

CONSTRUCTION WORK in PROGRESS - COMMON UTILITY PLANT

Description of Project	Balance End of Year
Structures and Improvements	$ 814,829
Office Furniture and Equipment Acquisitions	-
Transportation Equipment	-
Stores Equipment	-
Tools and Equipment Acquisitions	-
Communication Equipment	-
Miscellaneous Equipment	-
Total Construction Work in Progress Common Utility Plant	$ 814,829

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

Total Common Utility Plant, Page 201, line 8		$ 1,000,501
Electric Department	60%	600,301
Gas Department	15%	150,075
Water Department	25%	250,125
		$ 1,000,501

DEPARTMENTAL ALLOCATION OF COMMON UTILITY PLANT MADE ON REVENUE BASIS

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

Total Common CWIP,Page 201,line 11		$ 814,829
Electric Department	60%	488,897
Gas Department	15%	122,225
Water Department	25%	203,707
		$ 814,829

Accumulated Provision for Depreciation of Common Utility Plant

	General Plant Account 119.300	General Other Account 119.400	Total
Balance Beginning of the Year	$ 597,234	$ 49,234	$ 646,468
Depreciation Provision for Year Charged to:			
Depreciation Expense	54,163	-	54,163
Other Clearing Accounts	-	-	-
Net Charges for Plant Retired:			
Book Cost of Plant Retired	(66,249)	(49,234)	(115,483)
Cost of Removal	-	-	-
Salvage	-	-	-
Net Charged for Plant Retired	(66,249)	(49,234)	(115,483)
Other Credits	-	-	-
Total Charged to Depreciation	(12,086)	(49,234)	(61,320)
Balance End of the Year	$ 585,148	$ -	$ 585,148

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.

Departmental Allocation of Accumulated Provision For Depreciation, Common Utility Plant Made on a Revenue Basis

Accumulated Provision for Depreciation, Page 201, line 14		$ 585,148
Electric Department	60%	351,089
Gas Department	15%	87,772
Water Department	25%	146,287
		$ 585,148

Note: The accumulated provision for depreciation referred to above is classified as depreciation on general plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7	Net Purchases-Day Ahead Market(Acct 555)	290,360,752	190,668,264	884,951,862	454,013,419
8	Net Sales-Day Ahead Market (Acct 447)	423,211	(1,184,122)	283,845	1,473
9	Net Purchases-Real Time Market(Acct 555)	25,783,942	27,473,726	56,990,836	30,057,875
10	Net Sales-Real Time Market (Account 447)	(13,728,071)	(6,479,314)	(15,063,552)	(55,198,845)
11	Access Charge	63,538	108,015	134,048	58,201
12	Ancillary Services	1,063,960	866,306	6,696,156	1,341,756
13	Cost Recovery	(2,437,601)	294,372	20,932,715	6,433,171
14	Day Ahead Energy-Congestion-Losses	(79,633,523)	(58,346,537)	(157,724,642)	(33,527,466)
15	Hour Ahead Scheduling Process-RT Settlet	(5,035,550)	(2,928,390)	(26,180,216)	(23,589,357)
16	GMC	11,208,095	12,837,391	16,489,199	11,367,356
17	FERC Fees	1,213,117	1,290,411	1,979,847	1,172,850
18	Other	3,583,415	(2,698,634)	(549,172)	4,452,806
19					
20					
21					
22					
23					
24					
25					
26					
27					
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41					
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43					
44					
45					
46	TOTAL	232,865,285	161,901,488	788,940,926	396,583,239

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 and #9.
(3) Amount based on new MRTU charge code.

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

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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

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Schedule Page: 397 Line No.: 10 Column: b

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Schedule Page: 397 Line No.: 10 Column: c

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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

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
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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.

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

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

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

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

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

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

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

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch		MWh				
2	Reactive Supply and Voltage		MW				
3	Regulation and Frequency Response	2,145,443	MW	26,761,629	2,468,653		-27,245,199
4	Energy Imbalance		MWh				
5	Operating Reserve - Spinning	2,252,520	MW	30,380,409	2,405,621		-21,955,616
6	Operating Reserve - Supplement	2,170,519	MW	10,170,971	4,553,229		-8,048,823
7	Other		MW				1,037,025
8	Total (Lines 1 thru 7)	6,568,482		67,313,009	9,427,503		-56,212,613

Schedule Page: 398 Line No.: 1 Column: b

"Scheduling, System Control and Dispatch" will be 0. Energy schedules will be recorded separately 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, 6696, 6090, 6750 and 6760. It also includes flexible ramping constraint (FRC) charge codes 7024, 7050, 7056, 7057 and 7058 and pay for performance charges codes 7251, 7256, 7261 and 7266 and Flexible Ramping Product (FRP) charge codes 7070, 7078, 7088, 7071 , 7076 , 7077 , 7081, 7087

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, 6196, 6710

Schedule Page: 398 Line No.: 6 Column: b

"Operating Reserve - Supplement" includes Non-Spinning Reserve at the ISO, charge code 6200, 6224, 6270, 6294, 6296 and 6720.

Schedule Page: 398 Line No.: 7 Column: b

"Other" includes black start energy charge code 3101 and Grid Management Charge 4560 for Market Services, a charge required by CAISO to provide Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: 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	13,157	29	18	12,448			710		
2	February	13,122	8	18	12,419			703		
3	March	12,666	1	19	12,028			639		
4	Total for Quarter 1				36,895			2,052		
5	April	14,255	9	18	13,450			805		
6	May	14,230	9	18	13,124			1,106		
7	June	17,517	14	17	16,093			1,424		
8	Total for Quarter 2				42,667			3,335		
9	July	23,766	6	17	22,352			1,414		
10	August	22,956	7	17	21,652			1,304		
11	September	18,603	18	17	17,302			1,301		
12	Total for Quarter 3				61,306			4,019		
13	October	17,429	1	16	16,555			874		
14	November	13,783	2	17	13,097			686		
15	December	13,579	6	18	12,969			610		
16	Total for Quarter 4				42,621			2,170		
17	Total Year to Date/Year				183,489			11,576		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/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)	73,486,722
3	Steam	1,964,851			
4	Nuclear	4,913,370	23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	3,269,848			
6	Hydro-Pumped Storage	276,870	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,463,898
7	Other	233,757			
8	Less Energy for Pumping	42,799	25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	10,615,897	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	174,193
10	Purchases	72,293,537	27	Total Energy Losses	4,831,486
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	82,956,299
12	Received				
13	Delivered	20			
14	Net Exchanges (Line 12 minus line 13)	-20			
15	Transmission For Other (Wheeling)				
16	Received	8,473,018			
17	Delivered	8,426,133			
18	Net Transmission for Other (Line 16 minus line 17)	46,885			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	82,956,299			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: SOUTHERN CALIFORNIA EDISON COMPANY

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	6,770,771	173,977	12,895	29	1900
30	February	5,090,498	191,332	12,972	8	1900
31	March	6,346,698	537,535	12,585	1	1900
32	April	6,194,602	224,623	14,209	10	1800
33	May	6,774,366	570,036	13,976	9	1800
34	June	6,938,538	326,910	17,173	14	1800
35	July	9,177,665	563,960	23,460	6	1700
36	August	8,940,928	308,374	22,627	7	1700
37	September	7,517,452	327,304	18,492	7	1700
38	October	7,119,102	669,118	17,249	1	1700
39	November	5,650,827	343,968	13,499	2	1700
40	December	6,434,852	226,759	13,352	6	1700
41	TOTAL	82,956,299	4,463,896			

Schedule Page: 401 Line No.: 22 Column: b

Excludes 11,159,586 direct access megawatt hours and 2,205,278 Customer Choice Aggregation megawatt hours.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Palo Verde* (b)	Plant Name: *Mira Loma Peaker* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear	Gas Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor	Outdoor
3	Year Originally Constructed	1986	2007
4	Year Last Unit was Installed	1988	2007
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	699.00	49.70
6	Net Peak Demand on Plant - MW (60 minutes)	653	49
7	Plant Hours Connected to Load	3771	533
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	622	49
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	330	3
12	Net Generation, Exclusive of Plant Use - KWh	4913369843	24008188
13	Cost of Plant: Land and Land Rights	2995311	0
14	Structures and Improvements	638687391	3258909
15	Equipment Costs	1346420384	66560010
16	Asset Retirement Costs	0	0
17	Total Cost	1988103086	69818919
18	Cost per KW of Installed Capacity (line 17/5) Including	2844.2104	1404.8072
19	Production Expenses: Oper, Supv, & Engr	14964967	335815
20	Fuel	35745202	1424642
21	Coolants and Water (Nuclear Plants Only)	7467947	0
22	Steam Expenses	5340275	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	5407315	0
26	Misc Steam (or Nuclear) Power Expenses	20601651	546064
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	2932431	96826
30	Maintenance of Structures	1187674	16793
31	Maintenance of Boiler (or reactor) Plant	9220271	0
32	Maintenance of Electric Plant	7133418	477906
33	Maintenance of Misc Steam (or Nuclear) Plant	2225755	121371
34	Total Production Expenses	112226906	3019417
35	Expenses per Net KWh	0.0228	0.1258

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	NUCLEAR			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Grams of	Uranium		GAS-Mcf		
38	Quantity (Units) of Fuel Burned	0	758906	0	0	235119	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	66992792	0	0	1034	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	47.101	0.000	0.000	6.059	0.000
41	Average Cost of Fuel per Unit Burned	0.000	47.101	0.000	0.000	6.059	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.703	0.000	0.000	5.860	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.007	0.000	0.000	0.059	0.000
44	Average BTU per KWh Net Generation	0.000	10.348	0.000	0.000	10126.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Line No.	Item (a)	Plant Name: *Grapeland Peaker* (b)			Plant Name: *McGrath Peaker* (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			2012		
4	Year Last Unit was Installed	2007			2012		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	49.90			49.00		
6	Net Peak Demand on Plant - MW (60 minutes)	48			49		
7	Plant Hours Connected to Load	410			453		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	50			49		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	3			3		
12	Net Generation, Exclusive of Plant Use - KWh	9891890			23962228		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	3525578			4032073		
15	Equipment Costs	76515921			96666467		
16	Asset Retirement Costs	0			0		
17	Total Cost	80041499			100698540		
18	Cost per KW of Installed Capacity (line 17/5) Including	1604.0381			2055.0722		
19	Production Expenses: Oper, Supv, & Engr	335347			345547		
20	Fuel	817914			2006465		
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	565740			473919		
27	Rents	0			1194		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	94816			94298		
30	Maintenance of Structures	16793			68652		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	429957			625707		
33	Maintenance of Misc Steam (or Nuclear) Plant	146753			86630		
34	Total Production Expenses	2407320			3702412		
35	Expenses per Net KWh	0.2434			0.1545		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	GAS-Mcf			GAS-Mcf		
38	Quantity (Units) of Fuel Burned	0	124961	0	0	235509	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	1035	0	0	1031	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	6.545	0.000	0.000	8.520	0.000
41	Average Cost of Fuel per Unit Burned	0.000	6.545	0.000	0.000	8.520	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	6.322	0.000	0.000	8.266	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.083	0.000	0.000	0.084	0.000
44	Average BTU per KWh Net Generation	0.000	13078.000	0.000	0.000	10130.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Plant Name: *Mountainview 3 & 4* (d)			Plant Name: *Barre Peaker* (e)			Plant Name: *Center Peaker* (f)			Line No.
		Gas Turbine			Gas Turbine			Gas Turbine	1
		Outdoor			Outdoor			Outdoor	2
		2005			2007			2007	3
		2006			2007			2007	4
		1072.00			49.00			49.90	5
		1050			50			47	6
		11211			764			489	7
		0			0			0	8
		1072			49			50	9
		0			0			0	10
		37			3			3	11
		1964851245			33129957			14862168	12
		3218368			0			526947	13
		57344869			2580620			3416608	14
		764954233			80278379			82842067	15
		0			0			0	16
		825517470			82858999			86785622	17
		770.0723			1691.0000			1739.1908	18
		2022905			335339			335009	19
		90940154			2564789			1291889	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		15329287			516710			540683	26
		0			0			0	27
		0			0			0	28
		1982401			94298			94298	29
		640613			16793			16793	30
		0			0			0	31
		14481803			383175			371424	32
		2330276			93889			121949	33
		127727439			4004993			2772045	34
		0.0650			0.1209			0.1865	35
GAS			GAS			GAS			36
GAS-Mcf			GAS-Mcf			GAS-Mcf			37
0	14524975	0	0	328370	0	0	175031	0	38
0	1033	0	0	1032	0	0	1033	0	39
0.000	6.261	0.000	0.000	7.811	0.000	0.000	7.381	0.000	40
0.000	6.261	0.000	0.000	7.811	0.000	0.000	7.381	0.000	41
0.000	6.061	0.000	0.000	7.568	0.000	0.000	7.146	0.000	42
0.000	0.046	0.000	0.000	0.077	0.000	0.000	0.087	0.000	43
0.000	7637.000	0.000	0.000	10230.000	0.000	0.000	12164.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Plant Name: *Offsite Storage* (d)			Plant Name: (e)			Plant Name: (f)			Line No.
Fuel Facilities									1
Storage/Pipelines									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
8555			0			0			13
0			0			0			14
0			0			0			15
0			0			0			16
8555			0			0			17
0			0			0			18
0			0			0			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
0			0			0			25
0			0			0			26
0			0			0			27
0			0			0			28
0			0			0			29
0			0			0			30
0			0			0			31
0			0			0			32
0			0			0			33
0			0			0			34
0.0000			0.0000			0.0000			35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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

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

Plant Name: (d)			Plant Name: (e)			Plant Name: (f)			Line No.
									1
									2
									3
									4
		0.00			0.00			0.00	5
		0			0			0	6
		0			0			0	7
		0			0			0	8
		0			0			0	9
		0			0			0	10
		0			0			0	11
		0			0			0	12
		0			0			0	13
		0			0			0	14
		0			0			0	15
		0			0			0	16
		0			0			0	17
		0			0			0	18
		0			0			0	19
		0			0			0	20
		0			0			0	21
		0			0			0	22
		0			0			0	23
		0			0			0	24
		0			0			0	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		0			0			0	30
		0			0			0	31
		0			0			0	32
		0			0			0	33
		0			0			0	34
		0.0000			0.0000			0.0000	35
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Palo Verde: Data reported is on an SCE-share basis, which is consistent with nuclear industry practice.

Schedule Page: 402 Line No.: -1 Column: c

Mira Loma 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 constantly and is only on-line as needed.

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

Barre 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 base-loaded and is on-line during peak hours as the need requires.

Schedule Page: 403 Line No.: -1 Column: f

Center 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 base-loaded and is on-line during peak hours as the need requires.

Schedule Page: 402 Line No.: 5 Column: b

Palo Verde: Data represents Total Installed Capacity reported on a SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2 and 3.

Schedule Page: 402 Line No.: 5 Column: c

Mira Loma Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited to 49 MW by gas turbine.

Schedule Page: 403 Line No.: 5 Column: e

Barre Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited to 49 MW by gas turbine.

Schedule Page: 403 Line No.: 5 Column: f

Center Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited to 49 MW gas turbine.

Schedule Page: 402 Line No.: 9 Column: b

Palo Verde: Data reported for Total when not limited by Condenser Water reported on a SCE-share basis. SCE is a 15.8% owner of Palo Verde 1, 2 and 3.

Schedule Page: 402 Line No.: 10 Column: b

Palo Verde: Not Applicable.

Schedule Page: 402 Line No.: 10 Column: c

Mira Loma Peaker: Not applicable.

Schedule Page: 403 Line No.: 10 Column: d

Mountainview 3 & 4: Not applicable.

Schedule Page: 403 Line No.: 10 Column: e

Barre Peaker: Not Applicable.

Schedule Page: 403 Line No.: 10 Column: f

Center Peaker: Not Applicable.

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

Palo Verde: Data reported for Total Average Number of Employees reported on a SCE share basis. SCE is a 15.8% owner of Palo Verde 1, 2, and 3.

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

Grapeland 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 consistantly and only on-line during peak summer hours as needed. Projected annual Kw usage is 10% of total capacity during operational requirements.

Schedule Page: 402.1 Line No.: -1 Column: c

McGrath 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 constantly and is only on-line as the need requires.

Schedule Page: 403.1 Line No.: -1 Column: d

Offsite Storage Pipelines

Schedule Page: 402.1 Line No.: 5 Column: b

Grapeland Peaker: Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited to 49 MW by gas turbine.

Schedule Page: 402.1 Line No.: 5 Column: c

McGrath Peaker*:* Generator Name Plate Rating is 60.5 MW at 15 degrees C and 0.85 Power Factor. Plant output is limited to 49 MW by gas turbine.

Schedule Page: 402.1 Line No.: 10 Column: b

Grapeland Peaker: Not Applicable.

Schedule Page: 402.1 Line No.: 10 Column: c

McGrath Peaker*:* Not applicable.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 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)	88.35	66.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	65	64
7	Plant Hours Connect to Load	8,747	8,758
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	88	67
10	(b) Under the Most Adverse Oper Conditions	88	67
11	Average Number of Employees	9	9
12	Net Generation, Exclusive of Plant Use - Kwh	344,766,715	321,724,754
13	Cost of Plant		
14	Land and Land Rights	0	1,344
15	Structures and Improvements	65,554,090	19,370,490
16	Reservoirs, Dams, and Waterways	7,322,581	5,389,503
17	Equipment Costs	37,219,941	28,190,120
18	Roads, Railroads, and Bridges	1,939,809	925,625
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	112,036,421	53,877,082
21	Cost per KW of Installed Capacity (line 20 / 5)	1,268.0976	810.1817
22	Production Expenses		
23	Operation Supervision and Engineering	119,517	90,149
24	Water for Power	287,699	216,548
25	Hydraulic Expenses	158,856	103,216
26	Electric Expenses	103,431	90,671
27	Misc Hydraulic Power Generation Expenses	1,000,405	685,521
28	Rents	136,900	103,043
29	Maintenance Supervision and Engineering	359,681	270,727
30	Maintenance of Structures	17,297	8,916
31	Maintenance of Reservoirs, Dams, and Waterways	106,435	311,609
32	Maintenance of Electric Plant	604,628	596,260
33	Maintenance of Misc Hydraulic Plant	167,735	88,388
34	Total Production Expenses (total 23 thru 33)	3,062,584	2,565,048
35	Expenses per net KWh	0.0089	0.0080

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 382 Plant Name: Borel (b)	FERC Licensed Project No. 67 Plant Name: Big Creek No. 2A (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1904	1928
4	Year Last Unit was Installed	1932	1928
5	Total installed cap (Gen name plate Rating in MW)	0.00	110.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	98
7	Plant Hours Connect to Load	0	8,325
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	99
10	(b) Under the Most Adverse Oper Conditions	0	99
11	Average Number of Employees	0	8
12	Net Generation, Exclusive of Plant Use - Kwh	-216,616	454,002,144
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	2,597,980
16	Reservoirs, Dams, and Waterways	0	5,693,470
17	Equipment Costs	0	19,463,559
18	Roads, Railroads, and Bridges	0	13,269
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	27,768,278
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	252.4389
22	Production Expenses		
23	Operation Supervision and Engineering	0	148,805
24	Water for Power	0	358,199
25	Hydraulic Expenses	18,635	158,984
26	Electric Expenses	1,814	126,890
27	Misc Hydraulic Power Generation Expenses	128	1,127,776
28	Rents	0	170,447
29	Maintenance Supervision and Engineering	0	447,820
30	Maintenance of Structures	6,223	12,764
31	Maintenance of Reservoirs, Dams, and Waterways	14,654	103,897
32	Maintenance of Electric Plant	275	253,470
33	Maintenance of Misc Hydraulic Plant	17,004	123,846
34	Total Production Expenses (total 23 thru 33)	58,733	3,032,898
35	Expenses per net KWh	0.0000	0.0067

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2290 Plant Name: Kern River No. 3 (b)	FERC Licensed Project No. 2085 Plant Name: Mammoth Pool (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Outdoor
3	Year Originally Constructed	1921	1960
4	Year Last Unit was Installed	1921	1960
5	Total installed cap (Gen name plate Rating in MW)	40.18	190.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	34	175
7	Plant Hours Connect to Load	7,811	6,900
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	36	178
10	(b) Under the Most Adverse Oper Conditions	36	178
11	Average Number of Employees	15	8
12	Net Generation, Exclusive of Plant Use - Kwh	120,120,238	443,428,252
13	Cost of Plant		
14	Land and Land Rights	266,104	161,028
15	Structures and Improvements	2,285,930	2,476,195
16	Reservoirs, Dams, and Waterways	36,076,653	19,609,898
17	Equipment Costs	18,274,784	25,734,619
18	Roads, Railroads, and Bridges	4,806,302	525,860
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	61,709,773	48,507,600
21	Cost per KW of Installed Capacity (line 20 / 5)	1,535.8331	255.3032
22	Production Expenses		
23	Operation Supervision and Engineering	770,172	257,027
24	Water for Power	565,881	618,708
25	Hydraulic Expenses	122,418	281,332
26	Electric Expenses	266,744	200,648
27	Misc Hydraulic Power Generation Expenses	1,554,050	1,868,969
28	Rents	179,123	294,408
29	Maintenance Supervision and Engineering	194,160	773,506
30	Maintenance of Structures	208,619	717
31	Maintenance of Reservoirs, Dams, and Waterways	64,905	355,512
32	Maintenance of Electric Plant	90,314	301,372
33	Maintenance of Misc Hydraulic Plant	127,989	195,234
34	Total Production Expenses (total 23 thru 33)	4,144,375	5,147,433
35	Expenses per net KWh	0.0345	0.0116

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: Big Crk Wtr Col 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		
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	3,543,903	0
15	Structures and Improvements	7,997,772	0
16	Reservoirs, Dams, and Waterways	131,385,384	0
17	Equipment Costs	2,506,626	0
18	Roads, Railroads, and Bridges	1,780,692	0
19	Asset Retirement Costs	0	444,453
20	TOTAL cost (Total of 14 thru 19)	147,214,377	444,453
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 67 Plant Name: Big Creek No. 8 (d)	FERC Licensed Project No. 2174 Plant Name: Portal Power Plant (e)	FERC Licensed Project No. 1388 Plant Name: Poole Plant (f)	Line No.
Storage	Storage	Storage	1
Conventional	Conventional	Conventional	2
1921	1956	1924	3
1929	1956	1924	4
75.00	10.80	11.25	5
63	10	11	6
8,144	2,386	8,183	7
			8
71	11	11	9
71	11	11	10
9	3	0	11
245,585,980	9,717,198	14,157,278	12
			13
0	34,761	75,235	14
4,345,285	2,497,247	8,819,711	15
3,380,255	3,475,173	422,387	16
23,604,930	9,469,605	17,028,432	17
672,760	278,037	0	18
0	0	0	19
32,003,230	15,754,823	26,345,765	20
426.7097	1,458.7799	2,341.8458	21
			22
101,458	14,610	183,336	23
244,227	35,169	158,441	24
132,415	23,121	28,812	25
97,741	18,223	2,478	26
753,143	114,858	594,615	27
116,214	16,735	50,153	28
305,331	43,968	102,638	29
24,807	1,208	1,089	30
72,857	10,104	103,211	31
307,390	95,283	83,757	32
96,200	40,161	13,728	33
2,251,783	413,440	1,322,258	34
0.0092	0.0425	0.0934	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 120 Plant Name: Big Creek No. 3 (d)	FERC Licensed Project No. 2017 Plant Name: Big Creek No. 4 (e)	FERC Licensed Project No. 1930 Plant Name: Kern River No. 1 (f)	Line No.
Storage	Storage	Run-of-River	1
Conventional	Conventional	Conventional	2
1923	1951	1907	3
1980	1951	1907	4
174.45	100.00	26.28	5
172	100	25	6
8,744	8,561	8,116	7
			8
175	100	26	9
175	100	26	10
9	10	0	11
678,768,327	279,726,540	160,351,861	12
			13
6,142	104,451	120,432	14
8,719,993	2,783,117	6,994,099	15
20,521,655	16,202,201	37,994,887	16
60,528,206	20,066,147	18,695,199	17
1,745,414	136,631	1,532,742	18
0	0	0	19
91,521,410	39,292,547	65,337,359	20
524.6283	392.9255	2,486.2009	21
			22
236,884	135,277	503,736	23
568,071	325,636	370,119	24
268,146	171,739	117,376	25
187,497	125,508	109,087	26
1,747,988	1,020,029	774,241	27
270,314	154,952	117,156	28
710,201	407,109	126,992	29
535	6,537	157,425	30
187,401	109,257	111,783	31
657,460	160,349	186,692	32
200,772	131,967	67,054	33
5,035,269	2,748,360	2,641,661	34
0.0074	0.0098	0.0165	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 Plant Res Fac (d)	FERC Licensed Project No. 1389 Plant Name: Rush Creek Res Fac (e)	FERC Licensed Project No. 1394 Plant Name: Bishop Plnt 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
211,569	992,853	114,225	15
6,335,251	12,009,269	11,879,572	16
2,711,970	18,267	7,504,212	17
0	268,727	194,511	18
0	0	0	19
9,266,534	13,289,116	19,833,445	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 1389 Plant Name: Rush Creek (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
21,955,095	0	0	12
			13
72,508	0	0	14
1,511,534	0	0	15
3,027,044	0	0	16
13,626,017	0	0	17
354,909	0	0	18
0	0	0	19
18,592,012	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
938	0	0	25
0	0	0	26
109,708	0	0	27
0	0	0	28
0	0	0	29
22,477	0	0	30
483,910	0	0	31
58,400	0	0	32
70,832	0	0	33
746,265	0	0	34
0.0340	0.0000	0.0000	35

Schedule Page: 406   Line No.: 1   Column: b
Big Creek No.1   Licensed Project No. 2175

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406   Line No.: 1   Column: c
Big Creek No.2   Licensed Project No. 2175

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406   Line No.: 1   Column: d
Big Creek No. 8   Licensed Project No.67

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406   Line No.: 1   Column: e
Portal Power Plant   Licensed Project No. 2174

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1   Line No.: -1   Column: b
Borel Licensed Project No. 382
Plant is retired.

Schedule Page: 406.1   Line No.: 1   Column: b
Borel Licensed Project No. 382
There is no KWH generated during the plan year.

Schedule Page: 406.1   Line No.: 1   Column: c
Big Creek No. 2A   Licensed Project No. 67

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1   Line No.: 1   Column: d
Big Creek No.3 Licensed Project No. 120

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.1   Line No.: 1   Column: e
Big Creek No.4 Licensed Project No. 2017

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Schedule Page: 406.2   Line No.: -2   Column: d
Poole Plant Reservoir Facilities
FERC Licensed Proj. No. 1388 and 1390

Schedule Page: 406.2   Line No.: -1   Column: d
Pool Plant Res Fac

FERC Licensed Project Number 1388 and 1390 - Poole Plant

Schedule Page: 406.2   Line No.: 1   Column: c
Mammoth Pool Licensed Project No. 2085

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 67 Plant Name: Eastwood (b)
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)	199
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	202
6	Plant Hours Connect to Load While Generating	267
7	Net Plant Capability (in megawatts)	200
8	Average Number of Employees	5
9	Generation, Exclusive of Plant Use - Kwh	276,869,544
10	Energy Used for Pumping	42,798,616
11	Net Output for Load (line 9 - line 10) - Kwh	234,070,928
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	50,429,325
15	Reservoirs, Dams, and Waterways	160,000,670
16	Water Wheels, Turbines, and Generators	31,458,434
17	Accessory Electric Equipment	16,010,132
18	Miscellaneous Powerplant Equipment	6,405,898
19	Roads, Railroads, and Bridges	2,687,590
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	266,992,049
22	Cost per KW of installed cap (line 21 / 4)	1,336.2965
23	Production Expenses	
24	Operation Supervision and Engineering	270,284
25	Water for Power	650,912
26	Pumped Storage Expenses	288,643
27	Electric Expenses	196,299
28	Misc Pumped Storage Power generation Expenses	1,976,526
29	Rents	309,594
30	Maintenance Supervision and Engineering	813,403
31	Maintenance of Structures	2,307
32	Maintenance of Reservoirs, Dams, and Waterways	217,676
33	Maintenance of Electric Plant	536,662
34	Maintenance of Misc Pumped Storage Plant	234,195
35	Production Exp Before Pumping Exp (24 thru 34)	5,496,501
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	5,496,501
38	Expenses per KWh (line 37 / 9)	0.0199

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
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			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

Schedule Page: 408 Line No.: 1 Column: b

All Big Creek Powerhouses are operated remotely from Big Creek Dispatch Center located in the town of Big Creek.

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.: 37 Column: b

Eastwood License Project No. 67:

Based on FERC Guidance, a new line 39 is needed. Line 39 - Expense per KWh of Generation and Pumping (Line37/(Line9 + Line 10) and the value should be $0.01719 (($5,496,501/319,668,160 KWh).

Schedule Page: 408 Line No.: 38 Column: b

Eastwood License Project No. 67:

Based on FERC Guidance, a new line 39 is needed. Line 39 - Expense per KWh of Generation and Pumping (Line37/(Line9 + Line 10) and the value should be $0.01719 (($5,496,501/319,668,160 KWh).

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Other Production					
2	Santa Catalina Island					
3	Unit 7 Diesel	1957	1.00			
4	Unit 8 Diesel	1964	1.50			
5	Unit 10 Diesel	1966	1.10			
6	Unit 12 Diesel	1976	1.60			
7	Unit 14 Diesel	1976	1.40			
8	Unit 15 Diesel	1994	2.80			
9	Micro-Turbines	2011	1.50			
10	TOTAL		10.90	5.5	29,494,610	99,627,140
11						
12						
13	Hydro					
14	Kaweah No.1	1929	2.25	1.5	4,463,818	23,953,011
15	Kaweah No.2	1929	1.80	1.9	6,045,817	9,825,568
16	Kaweah No.3	1913	4.80	4.4	11,794,227	12,500,216
17	Santa Ana No.1 & 2	1899	3.20	1.1	558,051	5,699,136
18	Santa Ana No.3	1999	3.10	1.7	2,917,797	25,092,220
19	Lower Tule	1909	2.52		-101,757	38,000,423
20	Mill Creek No.1	1893	0.80	0.8	2,256,121	2,244,218
21	Mill Creek No. 2 & 3	1903	3.00	1.6	7,572,563	3,400,106
22	Lytle Creek	1904	0.50	0.4	1,024,787	1,398,519
23	Fontana	1917	2.96	0.8	2,545,443	779,866
24	Sierra	1922	0.48	0.4	1,258,523	800,007
25	Ontario No.1	1902	0.60	0.6		5,887,973
26	Ontario No.2	1963	0.32	0.2	659,167	1,441,596
27	Bishop Creek No. 2	1908	7.32	5.3	27,938,228	14,683,720
28	Bishop Creek No. 3	1913	7.84	5.4	28,120,937	9,678,112
29	Bishop Creek No. 4	1905	7.97	8.5	47,530,506	28,605,807
30	Bishop Creek No. 5	1919	4.53	3.9	16,272,042	6,862,640
31	Bishop Creek No. 6	1913	1.60	2.0	5,869,950	5,587,696
32	San Gorgonio No. 1 & 2	1923				5,206,858
33	Lundy	1911	3.00	3.0	9,034,580	6,476,212
34						
35						
36						
37	Other:					
38	Solar Photovoltaic					
39	SC-CHINO-SOL	2009	1.00	0.4	364,794	6,989,060
40	SC-RIALTO3-SOL	2010	1.00	0.7	1,088,993	8,296,651
41	SC-REDLND5-SOL	2010	2.50	1.7	2,337,750	28,067,193
42	SC-ONTAR6-SOL	2011	2.00	1.8	2,967,613	20,422,698
43	SC-REDLND7-SOL	2010	2.50	2.4	3,853,287	26,899,413
44	SC-ONTAR8-SOL	2010	2.00	1.4	2,545,343	23,425,448
45	SC-ONTAR9-SOL	2011	1.00	0.5	827,181	11,874,587
46	SC-ETWIND10-SOL	2011	1.50	0.8	814,224	18,505,598

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	SC-REDLND11-SOL	2011	3.50	3.6	6,366,053	41,246,830
2	SC-ONTAR12-SOL	2010	0.50	0.5	705,506	6,616,116
3	SC-REDLND13-SO	2011	3.50	3.1	4,838,298	39,187,325
4	SC-ETWIND15-SOL	2011	3.50	2.4	4,219,928	20,040,107
5	SC-REDLND16-SO	2011	1.50	0.7	356,029	17,051,736
6	SC-ETWIND17-SOL	2011	3.50	2.5	3,839,606	37,306,491
7	SC-ETWIND18-SOL	2011	1.50	1.4	2,272,544	17,323,418
8	SC-REDLND22-SO	2010	2.00	1.8	2,547,265	12,202,499
9	SC-ETWIND23-SOL	2011	2.50	2.4	4,304,991	31,062,897
10	SC-ETWIND26-SOL	2011	6.00	4.9	7,518,188	70,752,534
11	SC-ETWIND27-SOL	2012	2.00	1.8	2,836,715	9,481,147
12	SC-VISTA28-SOL	2011	3.50	3.1	5,016,588	39,375,829
13	SC-ONTAR32-SOL	2011	1.50	1.3	2,245,080	13,518,117
14	SC-ONTAR33-SOL	2011	1.00	1.0	1,551,924	12,165,259
15	SC-VESTAL42-SOL	2010	5.00	4.6	7,419,751	45,765,916
16	SC-VALLY44-SOL	2012	8.00	6.2	9,614,920	65,654,041
17	SC-REDLND48-SOL	2013	5.00	4.4	7,852,219	19,550,664
18						
19	TOTAL SOLAR VOLTAIC				88,304,789	642,781,572
20						
21	Environmental Mitigation Services					
22	IT IMM Costs					
23	UC Santa Barbara Fuel Cell	2012			1,633,817	
24	CS San Bernardino Fuel Cell	2013			8,469,315	
25						
26						
27						
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
				Diesel		3
				Diesel		4
				Diesel		5
				Diesel		6
				Diesel		7
				Diesel		8
				Propane		9
9,140,105	3,817,720	6,813,279	1,327,419		4,060	10
						11
						12
						13
10,645,783	303,105		187,009			14
5,458,649	246,416		119,681			15
2,604,212	594,252		264,512			16
1,780,980	342,231		41,183			17
8,094,265	334,573		184,749			18
15,079,533	296,876		156,299			19
2,805,273	110,189		34,527			20
1,133,369	323,120		64,680			21
2,797,038	81,971		50,349			22
263,468	319,740		26,416			23
1,666,681	72,676		103,273			24
9,813,288	84,829		58,840			25
4,504,988	56,410		11,538			26
2,005,973	1,612,699		353,677			27
1,234,453	700,813		134,202			28
3,589,185	775,804		241,673			29
1,514,932	412,788		100,006			30
3,492,310	146,015		128,693			31
	43,739		104,812			32
2,158,737	314,756		138,204			33
						34
						35
						36
						37
						38
6,989,060	57,226		3,153			39
8,296,651	54,403		149,894			40
11,226,877	120,744		20,205			41
10,211,349	96,658		10,405			42
10,759,765	119,500		11,176			43
11,712,724	98,932		7,255			44
11,874,587	50,274		3,869			45
12,337,066	74,000		4,730			46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
11,784,808	168,022		-7,861			1
13,232,231	25,565		1,577			2
11,196,379	169,123		19,135			3
5,725,745	181,613		11,152			4
11,367,825	75,618		13,536			5
10,658,997	179,624		11,036			6
11,548,945	72,177		4,730			7
6,101,249	98,848		10,268			8
12,425,159	123,891		7,883			9
11,792,089	291,767		22,633			10
4,740,574	116,974		6,306			11
11,250,237	181,791		11,452			12
9,012,078	79,537		4,730			13
12,165,259	55,571		3,153			14
9,153,183	220,188		101,799			15
8,206,755	396,122		25,225			16
3,910,133	260,720		15,766			17
						18
	3,368,889		473,206			19
						20
	7,315,479					21
	1,533,150					22
	90,687	87,104	2,574			23
	23,308	565,330	138,105			24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
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Schedule Page: 410 Line No.: 17 Column: a
Licensed Projects:
Santa Ana #1 Project No. 1933. Santa Ana #2 decommissioned in 1998

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 18 Column: a
Licensed Projects:
Santa Ana #3 Project No. 1933

SCE owns and operates 5 non-licensed powerhouses: Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 19 Column: a
Licensed Projects:
Lower Tule Project No. 372

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 21 Column: a
Licensed Projects:
Mill Creek # 2 & 3 Project No. 1934. Mill Creek 2 is in the process of decommissioning.

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 22 Column: a
Licensed Projects:
Lytle Creek Project No. 1932

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 27 Column: a
Licensed Project:
Bishop Creek # 2 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 28 Column: a
Licensed Project:
Bishop Creek # 3 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 29 Column: a
Licensed Project:
Bishop Creek # 4 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 30 Column: a
Licensed Project:
Bishop Creek # 5 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 31 Column: a

Licensed Project:
Bishop Creek #6 Project No. 1394

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410 Line No.: 32 Column: a

Licensed Project:
San Gorgonio # 1 & 2 Project No. 344

Hydro Plants San Gorgonio 1 & 2 are in the process of being decommissioned.

Schedule Page: 410 Line No.: 32 Column: c

Retired.

Schedule Page: 410 Line No.: 32 Column: d

Retired.

Schedule Page: 410 Line No.: 33 Column: a

Licensed Project:
Lundy Project No. 1390

SCE owns and operates 5 non-licensed powerhouses; Mill Creek 1, Ontario 1, Ontario 2, Fontana, and Sierra operation and maintenance expenses for these powerhouses have been allocated to SCE's Small Hydro powerhouses.

Schedule Page: 410.1 Line No.: 19 Column: a

Solar sites do not have a reliable way to measure plant use.

All Solar sites are commercially certified by CAISO.

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	800KV LINES							
2	SYLMAR	CELILO (CA)	800.00	800.00	STEEL	14.20		2
3	SYLMAR	CELILO (CA)	800.00	800.00	STEEL	149.59		
4	SYLMAR	CELILO (CA)	800.00	800.00	UNDERGROU	3.68		
5	SYLMAR	CELILO (CA)	800.00	800.00	UNDERGROU	0.61		
6	SYLMAR	CELILO (NV)	800.00	800.00	STEEL	144.86		1
7								
8	500KV LINES							
9	MIDWAY	VINCENT NO.1 & 2	500.00	500.00	STEEL	225.49		2
10	LUGO	VINCENT NO 1 & 2	500.00	500.00	STEEL	94.39		2
11	LUGO	MOHAVE/NEVADA	500.00	500.00	STEEL	9.85		1
12	EL DORADO	LUGO (CA)	500.00	500.00	STEEL	150.67		1
13	EL DORADO	LUGO (NV)	500.00	500.00	STEEL	26.51		1
14	LUGO	MIRA LOMA NO 1, 2, & 3	500.00	500.00	STEEL	83.09	13.41	3
15	LUGO	MOHAVE (CA)	500.00	500.00	STEEL	165.96		1
16	EL DORADO	MOHAVE (NV)	500.00	500.00	STEEL	19.93		1
17	EL DORADO	MOENKOPI (NV)	500.00	500.00	STEEL	29.65		1
18	MIRA LOMA	SERRANO NO 1 & 2	500.00	500.00	STEEL	26.98	1.77	2
19	LUGO	VICTORVILLE	500.00	500.00	STEEL	7.57		1
20	MIDWAY	VINCENT NO.3	500.00	500.00	STEEL	52.62		1
21	DEVERS	PALO VERDE CALIF	500.00	500.00	STEEL	126.45		1
22	DEVERS	PALO VERDE ARIZONA	500.00	500.00	STEEL	112.05		1
23	DEVERS	VALLEY	500.00	500.00	STEEL	41.60		1
24	SERRANO	VALLEY	500.00	500.00	STEEL	40.52		1
25	MIRA LOMA	VINCENT	500.00	500.00	STEEL	65.00		1
26	RANCHO VISTA	LUGO	500.00	500.00	STEEL	35.50		1
27	COLORADO RIVER	PALO VERDE	500.00	500.00	STEEL	226.80		4
28	ELDORADO	MCCULLOUGH	500.00	500.00	STEEL	0.60		1
29	LAUGHLIN	MOHAVE NO. 2	500.00	500.00	STEEL	0.04		1
30	ANTELOPE	WINDHUB	500.00	500.00	STEEL	25.45		1
31	ANTELOPE	WHIRLWIND	500.00	500.00	STEEL	14.49		1
32	WHIRLWIND	WINDHUB	500.00	500.00	STEEL	16.13		1
33	ANTELOPE	VINCENT NO. 2	500.00	500.00	STEEL	17.42		1
34	ANTELOPE	VINCENT NO. 1	500.00	500.00	STEEL	17.40		1
35	LAUGHLIN	MOHAVE	500.00	500.00	STEEL	0.22		2
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	500KV LINES CONT'D							
2	LAUGHLIN	MOHAVE-NO.1	500.00	500.00	STEEL	0.11		
3	LUGO	VICTORVILLE	500.00	500.00	STEEL	15.10		1
4	MIDWAY	WHIRLWIND	500.00	500.00	STEEL	36.45		1
5	INLAND EMPIRE	VALLEY	500.00	500.00	STEEL	0.92		1
6	MIDWAY	WHIRLWIND	500.00	500.00	STEEL	76.55		1
7	COLORADO RIVER	PALO VERDE	500.00	500.00	STEEL	128.60		1
8	DEVERS	VALLEY-NO.1	500.00	500.00	STEEL	41.50		1
9	DEVERS	VALLEY-NO.2	500.00	500.00	STEEL	41.50		1
10								
11	220KV LINES							
12	PARDEE	SYLMAR NO 1 & 2	220.00	220.00	STEEL	6.53	6.47	2
13	EAGLE ROCK	SYLMAR	220.00	220.00	STEEL	0.04	1.75	1
14	PARDEE	VINCENT	220.00	220.00	STEEL POLE	2.13		4
15	PARDEE	VINCENT	220.00	220.00	STEEL	14.03		
16	SANTA CLARA	VINCENT	220.00	220.00	STEEL	0.28		1
17	SANTA CLARA	VINCENT	220.00	220.00	STEEL	2.46		
18	RIO HONDO	VINCENT NO.2	220.00	220.00	STEEL	4.42		1
19	PARDEE	VARIOUS	220.00	220.00	STEEL POLE	0.14		21
20	PARDEE	VARIOUS	220.00	220.00	STEEL POLE	1.79		
21	PARDEE	VARIOUS	220.00	220.00	STEEL POLE	0.97		
22	PARDEE	VARIOUS	220.00	220.00	STEEL	0.50	0.11	
23	PARDEE	VARIOUS	220.00	220.00	STEEL	133.10	8.79	
24	PARDEE	VARIOUS	220.00	220.00	STEEL	30.95	31.95	
25	PARDEE	VARIOUS	220.00	220.00	STEEL	57.17		
26	PARDEE	VARIOUS	220.00	220.00	STEEL	74.59		
27	PARDEE	VARIOUS	220.00	220.00	STEEL	12.08		
28	PARDEE	VARIOUS	220.00	220.00	WOOD	0.07		
29	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL POLE	0.13		6
30	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL POLE	0.08		
31	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL POLE	0.30		
32	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL	1.66	2.45	
33	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL	1.06		
34	COGEN/RENEWABLES	VARIOUS	220.00	220.00	STEEL	0.34	2.40	
35	DEVERS	VARIOUS	220.00	220.00	STEEL	32.69	16.62	10
36					TOTAL	11,514.89	2,330.48	1,285

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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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.
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	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	220KV LINES CONT'D							
2	DEVERS	VARIOUS	220.00	220.00	STEEL	89.35		
3	DEVERS	VARIOUS	220.00	220.00	UNDERGROU	0.04		
4	DEVERS	VARIOUS	220.00	220.00	WOOD	0.16	0.07	
5	DEVERS	VARIOUS	220.00	220.00	WOOD	4.77		
6	ANTELOPE	VARIOUS	220.00	220.00	STEEL	135.29	15.49	10
7	ANTELOPE	VARIOUS	220.00	220.00	STEEL	0.32		
8	ANTELOPE	VARIOUS	220.00	220.00	STEEL	76.31		
9	CHINO	VARIOUS	220.00	220.00	STEEL	85.39	83.81	5
10	COACHELLA VALLEY	DEVERS	220.00	220.00	STEEL	0.10	0.28	1
11	BIG CREEK NO.3	BIG CREEK NO.4	220.00	220.00	STEEL	5.79		1
12	BIG CREEK 3	SPRINGVILLE	220.00	220.00	STEEL POLE	0.10		2
13	BIG CREEK 3	SPRINGVILLE	220.00	220.00	STEEL	127.05		
14	BIG CREEK 3	SPRINGVILLE	220.00	220.00	WOOD	1.17		
15	LAGUNA BELL	VARIOUS	220.00	220.00	STEEL POLE	0.15		13
16	LAGUNA BELL	VARIOUS	220.00	220.00	STEEL POLE	0.11		
17	LAGUNA BELL	VARIOUS	220.00	220.00	STEEL	55.54	39.95	
18	LAGUNA BELL	VARIOUS	220.00	220.00	STEEL	29.45	0.03	
19	LAGUNA BELL	VARIOUS	220.00	220.00	STEEL	4.32		
20	HINSON	VARIOUS	220.00	220.00	STEEL	6.29	5.67	4
21	HINSON	VARIOUS	220.00	220.00	STEEL	0.09	0.82	
22	HINSON	VARIOUS	220.00	220.00	STEEL	8.93	5.27	
23	EL NIDO	VARIOUS	220.00	220.00	STEEL POLE	0.33		13
24	EL NIDO	VARIOUS	220.00	220.00	STEEL POLE	19.92	0.41	
25	EL NIDO	VARIOUS	220.00	220.00	STEEL	18.15	16.58	
26	EL NIDO	VARIOUS	220.00	220.00	STEEL	14.49	13.22	
27	EL NIDO	VARIOUS	220.00	220.00	STEEL	3.69	3.69	
28	EL NIDO	VARIOUS	220.00	220.00	UNDERGROU	0.95		
29	PISGAH NO 2	VARIOUS	220.00	220.00	STEEL	0.07		5
30	PISGAH NO 2	VARIOUS	220.00	220.00	STEEL	3.43		
31	PISGAH NO 2	VARIOUS	220.00	220.00	STEEL	300.97		
32	PISGAH NO 2	VARIOUS	220.00	220.00	WOOD	0.72		
33	MIRA LOMA	VARIOUS	220.00	220.00	STEEL POLE	0.05		16
34	MIRA LOMA	VARIOUS	220.00	220.00	STEEL POLE	0.14		
35	MIRA LOMA	VARIOUS	220.00	220.00	STEEL POLE	0.12		
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	220KV LINES CONT'D							
2	MIRA LOMA	VARIOUS	220.00	220.00	STEEL	66.12	56.94	
3	MIRA LOMA	VARIOUS	220.00	220.00	STEEL	7.58	6.90	
4	MIRA LOMA	VARIOUS	220.00	220.00	STEEL	12.71	2.16	
5	MIRA LOMA	VARIOUS	220.00	220.00	STEEL	3.04		
6	CENTER	VARIOUS	220.00	220.00	STEEL POLE	0.36		9
7	CENTER	VARIOUS	220.00	220.00	STEEL	63.50	54.08	
8	CENTER	VARIOUS	220.00	220.00	STEEL	19.70		
9	ALAMITOS	VARIOUS	220.00	220.00	STEEL POLE	0.06		14
10	ALAMITOS	VARIOUS	220.00	220.00	STEEL	74.63	30.44	
11	ALAMITOS	VARIOUS	220.00	220.00	STEEL	9.94	9.60	
12	BIG CREEK 4	SPRINGVILLE	220.00	220.00	STEEL POLE	0.12		2
13	BIG CREEK 4	SPRINGVILLE	220.00	220.00	STEEL	134.12		
14	BIG CREEK 4	SPRINGVILLE	220.00	220.00	WOOD	1.17		
15	MOORPARK	VARIOUS	220.00	220.00	STEEL	125.35	123.46	15
16	MOORPARK	VARIOUS	220.00	220.00	STEEL	96.32	69.62	
17	CIMA	PISGAH (NV)	220.00	220.00	STEEL	8.53		4
18	CIMA	PISGAH (NV)	220.00	220.00	STEEL	75.94	0.63	
19	KRAMER	VARIOUS	220.00	220.00	STEEL POLE	0.05		6
20	KRAMER	VARIOUS	220.00	220.00	STEEL	59.70	57.72	
21	KRAMER	VARIOUS	220.00	220.00	STEEL	44.41	44.27	
22	EL DORADO	MEAD (NV)	220.00	220.00	STEEL	10.21		2
23	SANTA CLARA	VINCENT	220.00	220.00	STEEL	0.24		1
24	SANTA CLARA	VINCENT	220.00	220.00	STEEL	27.24		
25	PEARBLOSSOM	VINCENT	220.00	220.00	STEEL	0.88		1
26	PEARBLOSSOM	VINCENT	220.00	220.00	WOOD	12.25		
27	ELLIS	SANTIAGO NO 1 & 2	220.00	220.00	STEEL POLE	9.29	9.29	3
28	ELLIS	SANTIAGO NO 1 & 2	220.00	220.00	STEEL	5.64	5.28	
29	RIO HONDO	VINCENT NO.2	220.00	220.00	STEEL	20.57		1
30	BIG CREEK NO 2	BIG CREEK NO.8	220.00	220.00	STEEL	3.40		2
31	BIG CREEK NO 2	BIG CREEK NO.8	220.00	220.00	STEEL	5.62		
32	BIG CREEK NO 3	MAMMOTH POOL	220.00	220.00	STEEL	6.50		1
33	BIG CREEK	VARIOUS	220.00	220.00	STEEL POLE	2.28		9
34	BIG CREEK	VARIOUS	220.00	220.00	STEEL POLE	0.13		
35	BIG CREEK	VARIOUS	220.00	220.00	STEEL POLE	0.12		
36					TOTAL	11,514.89	2,330.48	1,285

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	220KV LINES CONT'D							
2	BIG CREEK	VARIOUS	220.00	220.00	STEEL	0.08	7.04	
3	BIG CREEK	VARIOUS	220.00	220.00	STEEL	28.85		
4	BIG CREEK	VARIOUS	220.00	220.00	STEEL	253.22	0.23	
5	BIG CREEK	VARIOUS	220.00	220.00	STEEL	5.67		
6	SERRANO	VILLA PARK NO.1 & 2	220.00	220.00	STEEL	3.39	3.11	2
7	BIG CREEK 1	EASTWOOD	220.00	220.00	STEEL POLE	0.10		1
8	BIG CREEK 1	EASTWOOD	220.00	220.00	STEEL	4.55		
9	LEBEC	PASTORIA	220.00	220.00	STEEL	0.02		1
10	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	STEEL	1.30		3
11	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	STEEL	52.06		
12	BIG CREEK-NO.3	RECTOR-NO.1	220.00	220.00	STEEL	10.98		
13	BIG CREEK-NO.3	RECTOR-NO.2	220.00	220.00	STEEL	74.59		
14	RECTOR	SPRINGVILLE	220.00	220.00	POLE 22	47.67		
15	Walcreek	WALNUT	220.00	220.00	POLE	0.35		1
16	MESA	VINCENT-NO.1	220.00	220.00	STEEL	36.27		1
17	PADUA	RANCHO VISTA-NO.1&2	220.00	220.00	STEEL	27.77		2
18	PADUA	RANCHO VISTA-NO.1&2	220.00	220.00	STEEL	1.31		
19	EAGLE ROCK	GOULD	220.00	220.00	STEEL	23.52		2
20	LAGUNA BELL	VELASCO	220.00	220.00	STEEL	2.50		
21	BUCK BLVD.	JULIAN HINDS	220.00	220.00	POLE	0.03		3
22	DESERT SUNLIGHT	RED BLUFF	220.00	220.00	POLE	0.16		
23	DEVERS	SENTINEL	220.00	220.00	POLE	0.41		
24	DEVERS	MIRAGE-NO.1&2	220.00	220.00	STEEL	30.32		6
25	DEVERS	EL CASCO	220.00	220.00	STEEL	17.04		
26	DEVERS	EL CASCO	220.00	220.00	WOOD	12.40		
27	DEVERS	SAN BERNARDINO	220.00	220.00	N/A	0.24		
28	DEVERS	SAN BERNARDINO	220.00	220.00	STEEL	39.44		
29	DEVERS	SAN BERNARDINO	220.00	220.00	STEEL	3.12		
30	EL CASCO	SAN BERNARDINO	220.00	220.00	STEEL	10.44		
31	EL CASCO	SAN BERNARDINO	220.00	220.00	STEEL	3.43		
32	MIRAGE	RAMON (IID)	220.00	220.00	STEEL	0.06		
33	COACHELLA VALLEY	MIRAGE	220.00	220.00	STEEL	0.82		1
34	ETIWANDA	RANCHO VISTA-NO.1&2	220.00	220.00	STEEL	0.92		4
35	MIRA LOMA	RANCHO VISTA-NO.1	220.00	220.00	STEEL	6.39		
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	220KV LINES CONT'D							
2	MIRA LOMA	RANCHO VISTA-NO.2	220.00	220.00	STEEL	6.39		
3	MIRA LOMA	RANCHO VISTA-NO.2	220.00	220.00	STEEL	0.50		
4	MIRA LOMA	RANCHO VISTA-NO.1	220.00	220.00	STEEL	0.50		
5	MOUNTAINVIEW	SAN BERNARDINO-NO.3&4	220.00	220.00	POLE	0.55		2
6	RANCHO VISTA	LUGO	220.00	220.00	STEEL	0.27		1
7	CALDWELL	VICTOR	220.00	220.00	STEEL POLE	1.64		1
8	CALDWELL	VICTOR	220.00	220.00	STEEL	5.97		
9	ELDORADO	MCCULLOUGH	220.00	220.00	STEEL	2.20		13
10	ELDORADO	MCCULLOUGH	220.00	220.00	STEEL	0.48		
11	ELDORADO	MCCULLOUGH	220.00	220.00	POLE	0.05		
12	ELDORADO	MCCULLOUGH	220.00	220.00	N/A	0.96		
13	ELDORADO	MCCULLOUGH	220.00	220.00	STEEL	0.43		
14	ELDORADO	MCCULLOUGH	220.00	220.00	N/A	1.85		
15	ELDORADO	MCCULLOUGH	220.00	220.00	STEEL	0.21		
16	ELDORADO	MCCULLOUGH	220.00	220.00	POLE	0.37		
17	ELDORADO	MCCULLOUGH	220.00	220.00	STEEL	0.19		
18	HIGHWIND	WINDHUB	220.00	220.00	STEEL	9.60		1
19	BLM WEST	KRAMER	220.00	220.00	STEEL	49.50		8
20	BLM WEST	KRAMER	220.00	220.00	N/A	27.00		
21	COOL WATER	KRAMER	220.00	220.00	STEEL	45.60		
22	COOL WATER	SANDLOT	220.00	220.00	STEEL	30.12		
23	KRAMER	SANDLOT	220.00	220.00	STEEL	14.33		
24	KRAMER	VICTOR-NO.2	220.00	220.00	STEEL	37.50		
25	LUGO	VICTOR-NO.3	220.00	220.00	STEEL	10.40		
26	LUGO	VICTOR-NO.4	220.00	220.00	STEEL	10.40		
27	HOOVER	MEAD-NO.3	220.00	220.00	STEEL	24.97		1
28	KRAMER	VICTOR NO.1	220.00	220.00	STEEL	37.50		1
29	VINCENT	VARIOUS	220.00	220.00	STEEL	13.10		1
30	DEVERS	VARIOUS	220.00	220.00	STEEL POLE	0.61		3
31	DEVERS	VARIOUS	220.00	220.00	STEEL	8.11		
32	DEVERS	VARIOUS	220.00	220.00	STEEL	47.24	39.72	
33	DEVERS	VARIOUS	220.00	220.00	WOOD	9.05		
34	DEVERS	VARIOUS	220.00	220.00	WOOD	15.57		
35	PRIMM	SILVER STATE	220.00	220.00	POLE	0.04		1
36					TOTAL	11,514.89	2,330.48	1,285

TRANSMISSION LINE STATISTICS

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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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	220KV LINES CONT'D							
2	SAN ONOFRE	VIEJO	220.00	220.00	STEEL	22.05		
3	BARRE	ELLIS-NO.1&2&3&4	220.00	220.00	STEEL	50.80		4
4	BARRE	DEL AMO	220.00	220.00	POLE	9.70		1
5	CHINO	VIEJO	220.00	220.00	STEEL	25.60		1
6	ELDORADO	IVANPAH	220.00	220.00	STEEL	34.40		1
7	IVANPAH	PRIMM	220.00	220.00	STEEL	9.66		1
8	KRAMER	VARIOUS	115.00	220.00	STEEL POLE	0.07		1
9	KRAMER	VARIOUS	115.00	220.00	STEEL	49.12		
10	KRAMER	VARIOUS	115.00	220.00	STEEL	0.02		
11	KRAMER	VARIOUS	115.00	220.00	STEEL	0.09		
12	KRAMER	VARIOUS	115.00	220.00	WOOD	0.12		
13	KRAMER	VARIOUS	115.00	220.00	WOOD	0.05		
14	CHINO	SOQUEL	66.00	220.00	STEEL POLE	0.37	0.76	1
15	CHINO	SOQUEL	66.00	220.00	STEEL	1.88		
16	CHINO	SOQUEL	66.00	220.00	WOOD POLE	0.17	0.06	
17	MIRA LOMA	VARIOUS	66.00	220.00	STEEL POLE	0.10		2
18	MIRA LOMA	VARIOUS	66.00	220.00	STEEL	3.82		
19								
20	161KV LINES							
21	EAGLE MOUNTAIN	BLYTHE	161.00	161.00	STEEL POLE	1.90	0.10	1
22			161.00	161.00	WOOD	50.64		
23			161.00	161.00	WOOD POLE	0.24		
24								
25	115KV LINES							134
26			115.00	115.00	STEEL POLE	0.48		
27			115.00	115.00	STEEL POLE	0.06		
28			115.00	115.00	STEEL POLE	0.21	0.03	
29			115.00	115.00	STEEL POLE	0.61		
30			115.00	115.00	STEEL POLE	5.31	0.68	
31			115.00	115.00	STEEL POLE	5.32	1.55	
32			115.00	115.00	STEEL POLE	1.91		
33			115.00	115.00	STEEL POLE	4.11	2.33	
34			115.00	115.00	STEEL POLE	4.19	0.18	
35			115.00	115.00	STEEL POLE	2.04		
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	115KV LINES CONT'D		115.00	115.00	STEEL POLE	0.35	0.32	
2			115.00	115.00	STEEL POLE	52.35	18.23	
3			115.00	115.00	STEEL POLE	4.13	0.23	
4			115.00	115.00	STEEL POLE	79.72	66.19	
5			115.00	115.00	STEEL	3.44		
6			115.00	115.00	STEEL	3.50	0.58	
7			115.00	115.00	STEEL	0.06	0.06	
8			115.00	115.00	STEEL	19.08	4.95	
9			115.00	115.00	STEEL	163.49	0.23	
10			115.00	115.00	STEEL	207.80	133.29	
11			115.00	115.00	STEEL	7.69	9.80	
12			115.00	115.00	STEEL	2.66	2.84	
13			115.00	115.00	STEEL	6.96	3.51	
14			115.00	115.00	STEEL	1.34	0.27	
15			115.00	115.00	STEEL	1.37	1.14	
16			115.00	115.00	UNDERGROU	8.64	5.25	
17			115.00	115.00	WOOD	2.00		
18			115.00	115.00	WOOD	0.13		
19			115.00	115.00	WOOD	0.81		
20			115.00	115.00	WOOD	1.55		
21			115.00	115.00	WOOD	37.37		
22			115.00	115.00	WOOD	60.80		
23			115.00	115.00	WOOD	23.72		
24			115.00	115.00	WOOD	119.82	6.79	
25			115.00	115.00	WOOD	26.52	0.18	
26			115.00	115.00	WOOD	0.74	0.24	
27			115.00	115.00	WOOD	26.85	2.43	
28			115.00	115.00	WOOD	83.60		
29			115.00	115.00	WOOD	3.05	0.79	
30			115.00	115.00	WOOD POLE	0.02	0.20	
31			115.00	115.00	WOOD POLE	0.15		
32			115.00	115.00	WOOD POLE	6.40	0.32	
33			115.00	115.00	WOOD POLE	25.32		
34			115.00	115.00	WOOD POLE	73.73	0.03	
35			115.00	115.00	WOOD POLE	31.14		
36					TOTAL	11,514.89	2,330.48	1,285

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1	115KV LINES CONT'D		115.00	115.00	WOOD POLE	36.17	0.84	
2			115.00	115.00	WOOD POLE	25.53	0.06	
3			115.00	115.00	WOOD POLE	7.41	0.26	
4			115.00	115.00	WOOD POLE	32.76		
5			115.00	115.00	WOOD POLE	2.02		
6			115.00	115.00	WOOD POLE	354.19	34.01	
7			115.00	115.00	WOOD POLE	5.06	0.13	
8			115.00	115.00	WOOD POLE	8.02	5.88	
9			66.00	115.00	STEEL POLE	0.02		
10			66.00	115.00	STEEL POLE	0.11		
11			66.00	115.00	STEEL POLE	0.01		
12			66.00	115.00	STEEL POLE	0.21	0.18	
13			66.00	115.00	STEEL	2.50		
14			66.00	115.00	STEEL	2.25	0.02	
15			66.00	115.00	STEEL	0.37		
16			66.00	115.00	WOOD	0.37		
17			66.00	115.00	WOOD POLE	0.09		
18			66.00	115.00	WOOD POLE	0.16		
19			66.00	115.00	WOOD POLE	0.25		
20			66.00	115.00	WOOD POLE	2.63	0.09	
21			66.00	115.00	WOOD POLE	2.13		
22			55.00	115.00	STEEL	1.36		
23			55.00	115.00	STEEL	0.02		
24			55.00	115.00	STEEL	0.02		
25			55.00	115.00	WOOD POLE	0.05		
26			55.00	115.00	WOOD POLE	0.16		
27			55.00	115.00	WOOD POLE	0.26		
28								
29	66KV LINES							829
30			66.00	66.00	STEEL POLE	0.02		
31			66.00	66.00	STEEL POLE	1.95	1.11	
32			66.00	66.00	STEEL POLE	15.86	1.41	
33			66.00	66.00	STEEL POLE	0.91	0.08	
34			66.00	66.00	STEEL POLE	20.91		
35			66.00	66.00	STEEL POLE	24.77	2.14	
36					TOTAL	11,514.89	2,330.48	1,285

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1	66KV LINES CONT'D		66.00	66.00	STEEL POLE	4.66	1.10	
2			66.00	66.00	STEEL POLE	0.12		
3			66.00	66.00	STEEL POLE	0.19	0.02	
4			66.00	66.00	STEEL POLE	0.60	0.08	
5			66.00	66.00	STEEL POLE	26.03	16.15	
6			66.00	66.00	STEEL POLE	1.71		
7			66.00	66.00	STEEL POLE	79.75	33.33	
8			66.00	66.00	STEEL POLE	260.15	125.17	
9			66.00	66.00	STEEL POLE	1.56		
10			66.00	66.00	STEEL POLE	0.15	0.11	
11			66.00	66.00	STEEL POLE	0.20	0.13	
12			66.00	66.00	STEEL POLE	0.29		
13			66.00	66.00	STEEL	0.41	1.24	
14			66.00	66.00	STEEL	3.84		
15			66.00	66.00	STEEL	68.98	9.93	
16			66.00	66.00	STEEL	0.97		
17			66.00	66.00	STEEL	0.24		
18			66.00	66.00	STEEL	102.59	67.94	
19			66.00	66.00	STEEL	12.37	9.62	
20			66.00	66.00	STEEL	216.56	164.35	
21			66.00	66.00	STEEL	2.42	1.53	
22			66.00	66.00	STEEL	0.07		
23			66.00	66.00	STEEL	125.81	89.00	
24			66.00	66.00	STEEL		1.76	
25			66.00	66.00	STEEL	64.53	49.36	
26			66.00	66.00	STEEL	0.03		
27			66.00	66.00	STEEL	1.08		
28			66.00	66.00	UNDERGROU	1.88		
29			66.00	66.00	UNDERGROU	0.39	0.19	
30			66.00	66.00	UNDERGROU	2.44		
31			66.00	66.00	UNDERGROU	8.04	0.04	
32			66.00	66.00	UNDERGROU	0.06		
33			66.00	66.00	UNDERGROU	151.25	51.36	
34			66.00	66.00	UNDERGROU	8.98	8.83	
35			66.00	66.00	UNDERGROU	4.86		
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	66KV LINES CONT'D		66.00	66.00	UNDERGROU	4.45	0.07	
2			66.00	66.00	UNDERGROU	0.20		
3			66.00	66.00	UNDERGROU	5.05	1.29	
4			66.00	66.00	WOOD	0.18		
5			66.00	66.00	WOOD		0.06	
6			66.00	66.00	WOOD	3.53	0.25	
7			66.00	66.00	WOOD	0.04	0.04	
8			66.00	66.00	WOOD	16.80		
9			66.00	66.00	WOOD	0.92		
10			66.00	66.00	WOOD	16.13	1.16	
11			66.00	66.00	WOOD	8.71	1.02	
12			66.00	66.00	WOOD	0.44		
13			66.00	66.00	WOOD	14.23	5.76	
14			66.00	66.00	WOOD	0.34		
15			66.00	66.00	WOOD	16.87	12.40	
16			66.00	66.00	WOOD	25.70	8.27	
17			66.00	66.00	WOOD	0.15		
18			66.00	66.00	WOOD POLE	21.13		
19			66.00	66.00	WOOD POLE	1.72	1.32	
20			66.00	66.00	WOOD POLE	0.02		
21			66.00	66.00	WOOD POLE		0.04	
22			66.00	66.00	WOOD POLE	228.60	12.76	
23			66.00	66.00	WOOD POLE	20.65	2.35	
24			66.00	66.00	WOOD POLE	21.33	12.55	
25			66.00	66.00	WOOD POLE	0.57		
26			66.00	66.00	WOOD POLE	234.31	45.09	
27			66.00	66.00	WOOD POLE	91.62	9.70	
28			66.00	66.00	WOOD POLE	4.96	1.02	
29			66.00	66.00	WOOD POLE	6.10	0.97	
30			66.00	66.00	WOOD POLE	49.17	2.85	
31			66.00	66.00	WOOD POLE	315.06	72.36	
32			66.00	66.00	WOOD POLE	0.02		
33			66.00	66.00	WOOD POLE	34.37	1.44	
34			66.00	66.00	WOOD POLE	738.67	139.66	
35			66.00	66.00	WOOD POLE	748.67	250.10	
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	66KV LINES CONT'D		66.00	66.00	WOOD POLE	0.73		
2			66.00	66.00	WOOD POLE	0.02		
3			66.00	66.00	WOOD POLE	2.55		
4								
5								
6	55KV LINES							8
7			55.00	55.00	STEEL POLE	0.30		
8			55.00	55.00	STEEL POLE	0.04		
9			55.00	55.00	STEEL POLE		0.04	
10			55.00	55.00	STEEL POLE	0.35		
11			55.00	55.00	STEEL POLE	0.06		
12			55.00	55.00	WOOD	0.79		
13			55.00	55.00	WOOD	0.92		
14			55.00	55.00	WOOD	0.63		
15			55.00	55.00	WOOD	0.03		
16			55.00	55.00	WOOD	0.41		
17			55.00	55.00	WOOD POLE	2.99		
18			55.00	55.00	WOOD POLE	6.68		
19			55.00	55.00	WOOD POLE	50.35	0.26	
20			55.00	55.00	WOOD POLE	7.77	0.64	
21			55.00	55.00	WOOD POLE	0.16		
22			55.00	55.00	WOOD POLE	15.91		
23			55.00	55.00	WOOD POLE	2.36		
24			55.00	55.00	WOOD POLE	6.74		
25								
26	33KV LINES							9
27			33.00	33.00	STEEL POLE	0.74		
28			33.00	33.00	STEEL POLE	0.15	0.48	
29			33.00	33.00	STEEL POLE	4.42		
30			33.00	33.00	STEEL POLE	0.08	0.04	
31			33.00	33.00	STEEL POLE	0.15	0.24	
32			33.00	33.00	STEEL POLE		0.02	
33			33.00	33.00	STEEL	8.32		
34			33.00	33.00	STEEL	0.05		
35			33.00	33.00	STEEL	0.02		
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	33KV LINES CONT'D		33.00	33.00	STEEL	0.08		
2			33.00	33.00	UNDERGROU	0.32	0.10	
3			33.00	33.00	UNDERGROU	1.19	0.18	
4			33.00	33.00	WOOD	0.33		
5			33.00	33.00	WOOD		0.26	
6			33.00	33.00	WOOD POLE	2.55	0.72	
7			33.00	33.00	WOOD POLE	4.53		
8			33.00	33.00	WOOD POLE	0.12		
9			33.00	33.00	WOOD POLE	5.83	2.43	
10			33.00	33.00	WOOD POLE	0.34		
11			33.00	33.00	WOOD POLE	4.12	9.94	
12			33.00	33.00	WOOD POLE	0.30	0.09	
13								
14	4705/4116 OTHER							
15	Rounding Adjustment							
16	Footnotes:							
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	11,514.89	2,330.48	1,285

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
1272 KCM ACSR	136,841	65,488,698	65,625,539					2
2312 KCM ACSR								3
1250 KCM XLP								4
300 KCM XLP GRD								5
2312 KCM ACSR	668,871	14,876,939	15,545,809					6
								7
								8
2156 KCM ACSR	3,706,358	46,112,158	49,818,515	26,343	33,657		60,000	9
2156 KCM ACSR	1,751,357	21,314,014	23,065,371	27,666	5,719		33,385	10
2156 KCM ACSR	177,040	1,989,137	2,166,177					11
2156 KCM ACSR	1,448,120	29,263,822	30,711,942	7,227	60,444		67,671	12
2156 KCM ACSR	36,677	7,577,907	7,614,584	3,104	2,862		5,966	13
2156 KCM ACSR	10,179,976	48,040,482	58,220,458	31,315	36,420	2,449	70,184	14
2156 KCM ACSR	607,445	28,678,285	29,285,730					15
2156 KCM ACSR	132,115	5,685,421	5,817,537	14,709	15,967		30,676	16
2156 KCM ACSR	151,231	5,932,890	6,084,122	1,981	94,775		96,756	17
2156 KCM ACSR	2,457,091	29,443,471	31,900,562	96,169	990,758	20,399	1,107,326	18
2156 KCM ACSR	748,912	2,287,338	3,036,250	4,935	26,890		31,825	19
2156 KCM ACSR	6,013,388	30,127,863	36,141,252	148,349	289,697	80,665	518,711	20
2156 KCM ACSR	15,244,178	436,918,489	452,162,668	26,234	286,422		312,656	21
2156 KCM ACSR	1,340,955	47,491,866	48,832,821	2,003	21,544	319,529	343,076	22
2156 KCM ACSR	28,679,833	271,331,087	300,010,920	125,304	207,504	96,688	429,496	23
2156 KCM ACSR	5,495,635	40,879,803	46,375,438	62,784	213,628		276,412	24
2-2156 ACSR	61,188,212	722,925,081	784,113,293					25
2156 Bundle ACSR		3,271,045	3,271,045					26
2156 Bundle ACSR								27
2-2156 ACSR								28
2-2156 ACSR								29
2-2156 Bundle ACS	16,796,780	64,886,849	81,683,629					30
2-2156 Bundle ACS	18,144,487	80,471,135	98,615,622					31
2156 KCM ACSR	71,262	76,831,987	76,903,249					32
2-2156 Bundle ACS	11,885,452	224,892,665	236,778,116					33
2-2156 Bundle ACS		237,004	237,004					34
2156 Bundle ACSR		7,296	7,296					35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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.
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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-2156 ACSR								2
2312 MCM Bundle		51,478	51,478					3
2-2156 Bundle ACS								4
2156 KCMIL Bundle								5
1-61-2B-2156								6
2156 Bundle ACSR								7
2156 Bundle ACSR								8
2156 Bundle ACSR								9
								10
								11
1590 KCM ACSR	225,218	1,181,220	1,406,438	53,516	123,462	146,908	323,885	12
1590 KCM ACSR	186,657	276,517	463,174	8,167	18,327	1,686,001	1,712,495	13
1033.5 KCM ACSR	145,317	521,234	666,551					14
1033.5 KCM ACSR								15
1033.5 KCM ACSR	33,954	1,169,080	1,203,034		14,314		14,314	16
2156 KCM ACSR								17
1033.5 KCM ACSR	72,932	1,904,976	1,977,908					18
1033.5 KCM ACSR	2,691,417	59,268,476	61,959,892	5,840	159,896		165,736	19
1590 KCM ACSR				14,304	87,032		101,336	20
605 KCM ACSR				4,177	1,518		5,695	21
1033 KCM SAC								22
1033.5 KCM ACSR								23
1590 KCM ACSR								24
605 KCM ACSR								25
605 KCM ACSR								26
666.6 KCM ACSR								27
605 KCM ACSR								28
1033.5 KCM ACSR	2,290,451	7,681,853	9,972,304	1,657	1,552		3,209	29
1590 KCM ACSR				5,268			5,268	30
954 KCM SAC				7,675	187,060	101,705	296,441	31
1033.5 KCM ACSR								32
1590 KCM ACSR								33
650 KCM CAL								34
1033.5 KCM ACSR	3,918,339	58,538,278	62,456,617	5,240	1,248		6,488	35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

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	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
605 KCM ACSR								2
3000 KCM HPOF								3
1033.5 KCM ACSR								4
605 KCM ACSR								5
1033.5 KCM ACSR	92,290,053	218,127,037	310,417,090	14,546	35,936	92	50,574	6
2156 KCM ACSR				1,560			1,560	7
605 KCM ACSR				2,771	847		3,619	8
1590 KCM ACSR	8,805,478	35,300,753	44,106,231	752,961	742,537	6,273	1,501,771	9
1033.5 KCM ACSR								10
605 KCM ACSR	31,372	418,220	449,593	15,198	1,866		17,064	11
1033.5 KCM ACSR	1,424,549	4,562,079	5,986,628	10,120	20,220		30,340	12
1033.5 KCM ACSR				44,599	260,160	16,362	321,121	13
1033.5 KCM ACSR				1,560	760		2,321	14
1033.5 KCM ACSR	3,514,705	30,270,529	33,785,234	12,957	21,577	1,389	35,923	15
1590 KCM ACSR				7,091	1,154		8,245	16
1033.5 KCM ACSR				3,904	947		4,850	17
1590 KCM ACSR								18
605 KCM ACSR								19
1033.5 KCM ACSR	1,634,441	7,342,280	8,976,722	361,259	943,481	1,993,445	3,298,185	20
1590 KCM ACSR								21
650 KCM CAL								22
1033.5 KCM ACSR	3,608,110	23,225,070	26,833,180	11,004	7,054		18,059	23
1590 KCM ACSR				13,978	127,215	25,369	166,561	24
1033.5 KCM ACSR								25
1590 KCM ACSR								26
336 KCM ACSR								27
3000 KCM HPOF								28
1033.5 KCM ACSR	1,155,551	8,962,169	10,117,719	2,960	92		3,052	29
605 KCM ACSR				33,557	10,049	15,905	59,512	30
605 KCM ACSR								31
605 KCM ACSR								32
1033.5 KCM ACSR	5,791,623	33,793,266	39,584,889	14,189	58,775		72,964	33
1590 KCM ACSR				224,618	246,128		470,746	34
605 KCM ACSR				34,783	76,740		111,522	35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
1033.5 KCM ACSR				25,802	71,325		97,127	2
1590 KCM ACSR				361,607	673,729	775,971	1,811,307	3
605 KCM ACSR								4
605 KCM ACSR								5
605 KCM ACSR	4,931,556	57,703,483	62,635,039	5,150	16,821		21,971	6
1033.5 KCM ACSR				11,313	84,086		95,400	7
605 KCM ACSR				20,140	165,661		185,801	8
1033.5 KCM ACSR	4,304,652	16,843,264	21,147,916	1,699	142,381		144,080	9
1033.5 KCM ACSR				1,724	876		2,599	10
1590 KCM ACSR								11
605 KCM ACSR	532,932	29,501,497	30,034,429	57			57	12
605 KCM ACSR								13
605 KCM ACSR								14
1033.5 KCM ACSR	13,288,604	54,735,110	68,023,714					15
1590 KCM ACSR								16
1033.5 KCM ACSR	25,048	1,197,458	1,222,506					17
605 KCM ACSR								18
1590 KCM ACSR	2,332,863	22,787,998	25,120,861	585,387	281,853	25,135	892,375	19
1033.5 KCM ACSR				16,722	119,148		135,870	20
1590 KCM ACSR								21
1033.5 KCM ACSR	11,017	1,261,083	1,272,100	10,903	11,484	584,427	606,813	22
1033.5 KCM ACSR	4,029,224	15,288,807	19,318,032	1,871			1,871	23
2156 KCM ACSR				6,859	4,266		11,125	24
605 KCM ACSR	332,719	1,568,943	1,901,662	805	68,943	64,865	134,613	25
605 KCM ACSR								26
1590 KCM ACSR	12,058,070	11,710,845	23,768,915	9,187	38,448		47,636	27
1590 KCM ACSR				3,752	51,030		54,782	28
2156 KCM ACSR	1,678,704	364,341,087	366,019,791					29
605 KCM ACSR	-63,110	300,481	237,371	4,116	640		4,756	30
666.6 KCM ACSR				4,167	752		4,919	31
605 KCM ACSR	42,221	788,996	831,217	8,346	11,164	5,671	25,181	32
1590 KCM ACSR	13,334,235	82,535,266	95,869,501	4,093	1,454		5,547	33
605 KCM ACSR				95,512	428,964		524,476	34
605 KCM ACSR								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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
1590 KCM ACSR								2
605 KCM ACSR								3
605 KCM ACSR								4
666.6 KCM ACSR								5
1590 KCM ACSR	78,248	2,918,602	2,996,850	132,810	260,030		392,840	6
605 KCM ACSR		6,678,804	6,678,804	7,510			7,510	7
605 KCM ACSR					287		287	8
2-1590 ACSR								9
1-666.6 ACSR		692,660	692,660					10
1-605 ACSR								11
1-1033 ACSR								12
1-1033 ACSR								13
1-1033 ACSR								14
2-1590 ACSR								15
2-1033 ACSR		28,942	28,942					16
2-1033 ACSR		33,651,138	33,651,138					17
2-1590 ACSR								18
605 ACSR		392,059	392,059					19
1-1033 ACSR								20
2-1590 ACSR								21
2-1033 ACSR								22
2-1590 ACSR								23
636 Bundle ACSS/T		156,159	156,159					24
1-1033 ACSR								25
1-1033.5 AAC STR.								26
1590 Bundle ACSR								27
1-605 ACSR								28
1-1033 ACSR								29
1-1033.5 AAC STR.								30
1-1033 ACSR								31
2-1334.6 ACSS/TW								32
2-B 1334.6 KCMIL		492,540	492,540					33
2-2156 Bundle ACS		1,559,320	1,559,320					34
2-1033 ACSR								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
2-1334.6 ACSS/TW								2
2-1590 ACSR								3
2-1590ACSR								4
1590 ACSR								5
2156 ACSR								6
1590 KCM ACSR								7
1590 KCM ACSR								8
954 Bundle ACSR								9
1-1033.5 KCMIL AC								10
1590 ACSR								11
1590 Bundle ACSR								12
2-B 1590 ACSR								13
1590 ACSR								14
2-1590 ACSR								15
2-1590 Bundle ACS								16
2-B 1590 ACSR								17
2-B 1590 ACSR	3,268,655	60,381,319	63,649,973					18
1033 ACSR		174,279	174,279	49,978	128,909		178,888	19
1590 Bundle ACSR								20
1590 ACSR								21
1590 ACSR								22
1590 ACSR								23
1033 ACSR								24
1033 ACSR								25
1033 ACSR								26
2-B 1590 ACSR	2,530,844	214,149,803	216,680,647					27
1033 ACSR	18,153,522	263,078,712	281,232,233					28
605 ACSR								29
1033.5 KCM ACSR	1,198,519	12,147,975	13,346,494					30
1033 KCM SAC								31
1033.5 KCM ACSR								32
1033 KCM SAC								33
1033.5 KCM ACSR								34
1590 ACSR		106,127	106,127					35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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-B 1590 MCM		349,910	349,910					2
1033 ACSR		93,275	93,275					3
1590 Bundle ACSR								4
2-B 1590 MCM								5
2-B 1590 ACSR								6
2-B 1590 ACSR								7
954 KCM SAC								8
1033.5 KCM ACSR								9
4/0 ACSR 6X1								10
954 KCM SAC								11
1033.5 KCM ACSR								12
4/0 ACSR 6X1								13
954 KCM SAC	50,427,355	1,457,049,706	1,507,477,061					14
954 KCM SAC								15
954 KCM SAC								16
605 KCM ACSR								17
605 KCM ACSR								18
								19
								20
336 KCM ACSR	38,155	3,101,263	3,139,418	403			403	21
336 KCM ACSR								22
336 KCM ACSR								23
								24
								25
1033 KCM SAC	203,792	9,066,500	9,270,292	10,045	33,526	1,228	44,800	26
1033.5 KCM ACSR				6,399	530		6,929	27
2/0 STRANDED CU								28
266.8 KCM ACSR								29
336 KCM ACSR								30
336.4 KCM ACSR 3								31
4/0 ACSR 5X1								32
4/0 ACSR 6X1								33
4/0 STRANDED CU								34
477 MCM AL								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
636 KCM SAC								1
653.9 KCM ACSR								2
795 KCM SAC								3
954 KCM SAC								4
115 KCM STRAND								5
2/0 STRANDED CU								6
336 KCM ACSR								7
336.4 KCM ACSR 3								8
4/0 ACSR 5X1								9
4/0 ACSR 6X1								10
4/0 STRANDED CU								11
636 KCM SAC								12
653.9 KCM ACSR								13
795 KCM SAC								14
954 KCM SAC								15
1750 KCM XLP								16
1033 KCM SAC								17
1033.5 KCM ACSR								18
2/0 STRANDED CU								19
266.8 KCM ACSR								20
336 KCM ACSR								21
336.4 KCM ACSR 3								22
4/0 ACSR 5X1								23
4/0 ACSR 6X1								24
4/0 STRANDED CU								25
636 KCM SAC								26
653.9 KCM ACSR								27
795 KCM SAC								28
954 KCM SAC								29
1033.5 KCM ACSR								30
115 KCM STRAND								31
2/0 STRANDED CU								32
266.8 KCM ACSR								33
336 KCM ACSR								34
336.4 KCM ACSR 3								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINE STATISTICS (Continued)

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4/0 ACSR 5X1								1
4/0 ACSR 6X1								2
4/0 STRANDED CU								3
477 MCM AL								4
636 KCM SAC								5
653.9 KCM ACSR								6
795 KCM SAC								7
954 KCM SAC								8
1033.5 KCM ACSR								9
2/0 STRANDED CU								10
4/0 STRANDED CU								11
954 KCM SAC								12
2/0 STRANDED CU								13
4/0 STRANDED CU								14
954 KCM SAC								15
4/0 STRANDED CU								16
2/0 STRANDED CU								17
336 KCM ACSR								18
336.4 KCM ACSR 3								19
4/0 STRANDED CU								20
954 KCM SAC								21
115 KCM STRAND								22
336 KCM ACSR								23
4/0 ACSR 6X1								24
115 KCM STRAND								25
336 KCM ACSR								26
4/0 ACSR 6X1								27
								28
								29
1/0 ACSR	1,427,432	196,079,841	197,507,273	46,944	2,110		49,054	30
1033.5 KCM ACSR				2,771	3,178		5,948	31
2/0 STRANDED CU				230,348	139,886		370,234	32
250 KCM					22		22	33
3/0 SOLID CU				34,631	480,874	25,953	541,457	34
336 KCM ACSR				19,882	241,468		261,350	35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

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336.4 KCM ACSR 3				5,337	2,732		8,070	1
336.4 KCM SAC				3,199	5,688		8,887	2
4/0 ACSR 5X1				47,826	175,222		223,049	3
4/0 SAC				19,127	6,145		25,272	4
4/0 STRANDED CU				10,972	136,909		147,881	5
605 KCM ACSR				2,029	841		2,870	6
653.9 KCM ACSR				20,156	167,315		187,471	7
954 KCM SAC				86,752	69,599		156,352	8
NO 2 SOLID CU				1,109	177		1,286	9
NO. 2 SAC				93,358	54,420		147,778	10
NO. 2 STRANDED				13,898			13,898	11
954 KCM ACSR				93,808	322,353		416,162	12
1033.5 KCM ACSR				1,602	1,901		3,502	13
1590 KCM ACSR				10,461	80,947		91,408	14
2/0 STRANDED CU				47,413	10,512		57,926	15
3/0 SOLID CU								16
300 KCM								17
336 KCM ACSR								18
336.4 KCM ACSR 3								19
4/0 STRANDED CU								20
605 KCM ACSR								21
605 KCM ACSR								22
653.9 KCM ACSR								23
666.6 KCM ACSR								24
954 KCM SAC								25
NO. 2 SAC								26
NO. 2 STRANDED								27
1000 KCM HPOF								28
1250 KCM XLP								29
1500 KCM EPR								30
1500 KCM XLP								31
1590 KCM ACSR								32
1750 KCM XLP								33
2000 KCM HPOF								34
500 KCM HPOF								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

TRANSMISSION LINE STATISTICS (Continued)

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750 KCM HPOF								1
954 KCM SAC								2
3000 KCM CU								3
3/0 SOLID CU								4
1033.5 KCM ACSR								5
2/0 STRANDED CU								6
250 KCM								7
3/0 SOLID CU								8
300 KCM								9
336 KCM ACSR								10
336.4 KCM ACSR 3								11
4/0 SAC								12
4/0 STRANDED CU								13
605 KCM ACSR								14
653.9 KCM ACSR								15
954 KCM SAC								16
NO. 2 SAC								17
1/0 ACSR								18
1033.5 KCM ACSR								19
1590 KCM ACSR								20
1750 KCM XLP								21
2/0 STRANDED CU								22
250 KCM								23
3/0 SOLID CU								24
300 KCM								25
336 KCM ACSR								26
336.4 KCM ACSR 3								27
336.4 KCM SAC								28
4/0 ACSR 5X1								29
4/0 SAC								30
4/0 STRANDED CU								31
400 KCM LPOF CU								32
605 KCM ACSR								33
653.9 KCM ACSR								34
954 KCM SAC								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	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)
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)	
NO 2 SOLID CU								1
NO. 2 SAC								2
NO. 2 STRANDED								3
								4
								5
								6
2/0 STRANDED CU	289,649	20,544,521	20,834,170	22,461	421,574	6,055	450,091	7
336 KCM ACSR				350	1,216		1,566	8
4/0 ACSR 5X1								9
4/0 ACSR 6X1								10
NO. 2 STRANDED								11
2/0 STRANDED CU								12
336 KCM ACSR								13
4/0 ACSR 6X1								14
NO. 2 ACSR								15
NO. 2 STRANDED								16
115 KCM STRAND								17
2/0 ACSR								18
2/0 STRANDED CU								19
336 KCM ACSR								20
4/0 ACSR 5X1								21
4/0 ACSR 6X1								22
NO. 2 ACSR								23
NO. 2 STRANDED								24
								25
								26
2/0 STRANDED CU	1,325	87,115	88,440	28,143	176,749		204,892	27
336 KCM ACSR				21,223	176,494		197,717	28
336.4 KCM ACSR 3				34,420	340,933	1,250,259	1,625,612	29
4/0 SAC								30
653.9 KCM ACSR								31
954 KCM SAC								32
2/0 STRANDED CU								33
336 KCM ACSR								34
4/0 STRANDED CU								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	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)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
653.9 KCM ACSR								1
1500 KCM XLP								2
750 KCM HPOF								3
336 KCM ACSR								4
653.9 KCM ACSR								5
2/0 STRANDED CU								6
336 KCM ACSR								7
336.4 KCM ACSR 3								8
4/0 SAC								9
4/0 STRANDED CU								10
653.9 KCM ACSR								11
954 KCM SAC								12
								13
				175,423	354,563	2,181,749	2,711,735	14
	-1	-1	-2					15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	449,338,613	5,743,102,134	6,192,440,747	4,707,582	11,406,369	9,434,492	25,548,449	36

Schedule Page: 422   Line No.: 1   Column: j

Amounts are totaled on the first row of each location.

Schedule Page: 422   Line No.: 1   Column: k

Amounts are totaled on the first row of each location.

Schedule Page: 422.12   Line No.: 16   Column: a

aSAP is the source system for this record
bSAP & SLD are the source systems for this record

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	OVERHEAD	CONSTRUCTION					
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16	UNDERGROUND	CONSTRUCTION					
17	San Bernardino	Redlands/Tennessee/Timoteo	1.37	UG		2	2
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		1.37			2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
3000	AL UG	OTH	66			6,430,813		6,430,813	17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
						6,430,813		6,430,813	44

Schedule Page: 424 Line No.: 17 Column: e

N/A

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	ANTELOPE-LANCASTER	TU	500.00	220.00	13.80
2	ANTELOPE-LANCASTER	TU	220.00	66.00	
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	CAMINO-TWENTY-NINE	TU	220.00	16.00	
7	CENTER-WHITTIER	TU	220.00	66.00	
8	CENTER-WHITTIER	TU	66.00	12.00	
9	CHEVMAIN-EL SEGUNDO	TU	220.00	66.00	
10	CHEVMAIN-EL SEGUNDO	TU	66.00	16.00	
11	CHEVMAIN-EL SEGUNDO	TU	66.00	13.20	
12	CHINO-ONTARIO	TU	220.00	66.00	
13	CHINO-ONTARIO	TU	72.00	12.00	
14	CHINO-ONTARIO	TU	66.00	12.00	
15	CIMA-HI DESERT	TU	220.00	16.00	
16	COLORADO RIVER-BLYTHE	TU	500.00	220.00	13.80
17	COLORADO RIVER-BLYTHE	TU	66.00	12.00	
18	COLORADO RIVER-BLYTHE	TU	66.00	4.00	
19	DEL AMO-LONG BEACH	TU	220.00	66.00	
20	DEL AMO-LONG BEACH	TU	66.00	12.00	
21	DEVERS-PALM SPRINGS	TA	500.00	220.00	
22	DEVERS-PALM SPRINGS	TA	220.00	115.00	13.80
23	DEVERS-PALM SPRINGS	TA	115.00	12.00	
24	EAGLE MOUNTAIN-BLYTHE	TU	220.00	161.00	12.00
25	EAGLE MOUNTAIN-BLYTHE	TU	220.00	66.00	72.00
26	EAGLE MOUNTAIN-BLYTHE	TU	220.00	66.00	12.00
27	EAGLE MOUNTAIN-BLYTHE	TU	66.00	12.00	
28	EAGLE ROCK-MONROVIA	TU	220.00	66.00	
29	EL CASCO-CALIMESA	TU	220.00	115.00	
30	EL CASCO-CALIMESA	TU	115.00	12.00	
31	EL NIDO-INGLEWOOD	TA	220.00	66.00	
32	EL NIDO-INGLEWOOD	TA	66.00	16.00	
33	ELDORADO-CLARK CO., N	TA	500.00	220.00	13.80
34	ELLIS-HUNTINGTON BEACH	TU	220.00	66.00	
35	ELLIS-HUNTINGTON BEACH	TU	66.00	12.00	
36	GOLETA-SANTA BARBARA	TU	220.00	66.00	
37	GOLETA-SANTA BARBARA	TU	66.00	16.00	
38	GOLETA-SANTA BARBARA	TU	66.00	12.00	
39	GOULD-MONROVIA	TU	220.00	66.00	
40	GOULD-MONROVIA	TU	66.00	16.00	

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	GOULD-MONROVIA	TU	33.00	16.00	
2	HINSON-LONG BEACH	TU	220.00	66.00	
3	INYO-BISHOP	TU	220.00	115.00	
4	IVANPAH-NIPTON	TU	220.00	115.00	
5	JOHANNA-SANTA ANA	TU	220.00	66.00	
6	JOHANNA-SANTA ANA	TU	66.00	12.00	
7	KRAMER-RIDGECREST	TU	230.00	115.00	
8	KRAMER-RIDGECREST	TU	115.00	33.00	
9	KRAMER-RIDGECREST	TU	33.00	2.40	
10	LA CIENEGA-SANTA MONICA	TU	220.00	66.00	
11	LA FRESA-REDONDO	TU	220.00	66.00	
12	LA FRESA-REDONDO	TU	66.00	16.00	
13	LAGUNA BELL-MONTEBELLO	TU	220.00	66.00	
14	LAGUNA BELL-MONTEBELLO	TU	66.00	16.00	
15	LIGHTHIPE-LONG BEACH	TA	220.00	66.00	
16	LIGHTHIPE-LONG BEACH	TA	66.00	12.00	
17	LUGO-HI DESERT	TA	500.00	220.00	
18	MESA-MONTEBELLO	TA	220.00	66.00	
19	MESA-MONTEBELLO	TA	66.00	16.00	
20	MESA-MONTEBELLO	TA	66.00	12.00	
21	MIRA LOMA-ONTARIO	TA	525.00	230.00	13.80
22	MIRA LOMA-ONTARIO	TA	230.00	70.00	
23	MIRA LOMA-ONTARIO	TA	66.00	12.00	
24	MIRAGE-PALM SPRINGS	TU	220.00	115.00	
25	MOORPARK-THOUSAND OAK	TU	220.00	66.00	
26	MOORPARK-THOUSAND OAK	TU	66.00	16.00	
27	OLINDA-FULLERTON	TU	220.00	66.00	
28	OLINDA-FULLERTON	TU	66.00	12.00	
29	PADUA-FOOTHILL	TU	220.00	66.00	
30	PADUA-FOOTHILL	TU	66.00	12.00	
31	RANCHO VISTA-ETIWANDA	TU	500.00	220.00	13.80
32	RECTOR-VISALIA	TA	230.00	66.00	
33	RECTOR-VISALIA	TA	230.00	9.50	
34	RECTOR-VISALIA	TA	66.00	12.00	
35	RECTOR-VISALIA	TA	66.00	4.00	
36	RED BLUFF-VIDAL	TU	500.00	220.00	13.80
37	RIO HONDO-MONROVIA	TU	230.00	66.00	
38	RIO HONDO-MONROVIA	TU	220.00	66.00	
39	RIO HONDO-MONROVIA	TU	66.00	16.00	
40	RIO HONDO-MONROVIA	TU	66.00	12.00	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAN BERNARDINO-INLAND	TU	220.00	66.00	
2	SAN BERNARDINO-INLAND	TU	66.00	12.00	
3	SANTA CLARA-VENTURA	TU	220.00	72.00	
4	SANTA CLARA-VENTURA	TU	220.00	66.00	
5	SANTIAGO-EL TORO	TU	220.00	66.00	
6	SANTIAGO-EL TORO	TU	66.00	33.00	
7	SANTIAGO-EL TORO	TU	66.00	12.00	
8	SAUGUS-SAN FERNANDO	TU	220.00	66.00	
9	SAUGUS-SAN FERNANDO	TU	66.00	16.00	
10	SERRANO-ORANGE	TU	500.00	220.00	
11	SPRINGVILLE-PORTERVILLE	TU	220.00	66.00	
12	SPRINGVILLE-PORTERVILLE	TU	66.00	12.00	
13	VALLEY-SAN JACINTO	TA	525.00	120.00	
14	VALLEY-SAN JACINTO	TA	115.00	12.00	
15	VESTAL-DELANO	TU	220.00	66.00	
16	VESTAL-DELANO	TU	66.00	12.00	
17	VICTOR-HI DESERT	TU	220.00	115.00	
18	VICTOR-HI DESERT	TU	115.00	33.00	
19	VICTOR-HI DESERT	TU	115.00	12.00	
20	VIEJO-LAKE FOREST	TU	220.00	66.00	
21	VIEJO-LAKE FOREST	TU	66.00	12.00	
22	VILLA PARK-SANTA ANA	TU	220.00	66.00	
23	VILLA PARK-SANTA ANA	TU	66.00	12.00	
24	VINCENT-LANCASTER	TA	500.00	220.00	
25	VISTA-INLAND	TA	220.00	115.00	
26	VISTA-INLAND	TA	220.00	66.00	
27	WALNUT-COVINA	TU	220.00	66.00	
28	WALNUT-COVINA	TU	66.00	12.00	
29	ALAMITOS-LONG BEACH	TU	220.00	66.00	
30	BIG CREEK 1-BIG CREEK	TU	230.00	13.10	
31	BIG CREEK 1-BIG CREEK	TU	33.00	14.40	
32	BIG CREEK 1-BIG CREEK	TU	33.90	7.40	
33	BIG CREEK 1-BIG CREEK	TU	13.40	7.20	
34	BIG CREEK 2-NR. BIG CREEK	TU	230.00	7.20	
35	BIG CREEK 2-NR. BIG CREEK	TU	220.00	13.80	
36	BIG CREEK 3-NR. AUBERRY	TU	240.00	13.80	
37	BIG CREEK 3-NR. AUBERRY	TU	230.00	13.80	
38	BIG CREEK 4-NR. AUBERRY	TU	240.00	11.50	
39	BIG CREEK 4-NR. AUERRY	TU	12.00	2.40	
40	BIG CREEK 8-NR. BIG CREEK	TU	240.00	13.50	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

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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.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	BOREL-LAKE ISABELLA	TU	66.00	2.40	
2	BUCKWIND-NORTH PALM SPRINGS	TU	115.00	12.47	
3	CHEVGEN-EL SEGUNDO	TU	66.00	13.80	
4	COOL WATER-DAGGETT	TU	115.00	13.20	
5	COOL WATER-DAGGETT	TU	115.00	4.16	
6	EASTWOOD-SHAVER LAKE	TU	220.00	13.80	
7	ETIWANDA-ETIWANDA	TU	230.00	18.00	
8	ETIWANDA-ETIWANDA	TU	220.00	66.00	
9	ETIWANDA-ETIWANDA	TU	220.00	16.00	
10	ETIWANDA-ETIWANDA	TU	67.00	16.00	
11	ETIWANDA-ETIWANDA	TU	66.00	12.00	
12	ETIWANDA-ETIWANDA	TU	66.00	4.00	
13	HUNTINGTON BEACH-HUNTINGTON BEACH	TU	66.00	4.00	
14	KAWEAH 1-THREE RIVERS	TU	66.00	2.40	
15	KAWEAH 2-THREE RIVERS	TU	66.00	2.40	
16	KAWEAH 3-THREE RIVERS	TU	72.00	2.40	
17	KERN RIVER 1-KERN CANYON	TU	70.00	2.60	
18	KERN RIVER 3-KERNVILLE	TU	71.54	11.00	
19	LUNDY-NR. LEE VINING	TU	55.00	16.00	
20	LUNDY-NR. LEE VINING	TU	55.00	2.40	
21	MAMMOTH POOL-BIG CREEK	TU	230.00	13.20	
22	MCGRATH BEACH-OXNARD	TU	66.00	13.00	
23	MIDWIND-LANCASTER	TU	66.00	12.00	
24	ORMOND BEACH-OXNARD	TU	220.00	66.00	
25	PEBBLY BEACH-AVALON	TU	12.00	2.40	
26	PARKER-BLYTHE	TU	161.00	66.00	
27	POOLE-NR. LEE VINING	TU	12.00	7.00	
28	POOLE-NR. LEE VINING	TU	7.20	122.00	
29	PORTAL-BIG CREEK	TU	33.00	4.00	
30	RENWIND-PALM SPRINGS	TU	115.00	12.47	
31	RUSH CREEK-NR. JUNE LAKE	TU	115.00	2.40	
32	SANTA ANA RIVER 1-FOOTHILL	TU	34.40	2.40	
33	SANTA ANA RIVER 3-FOOTHILL	TU	34.50	4.16	
34	SOUTHWIND-LANCASTER	TU	66.00	12.00	
35	VENWIND-PALM SPRINGS	TU	115.00	12.00	
36	WHIRLWIND-ROSAMOND	TU	500.00	220.00	13.80
37	WINDHUB-TEHACAHPI	TU	533.00	220.00	13.80
38	WINDHUB-TEHACAHPI	TU	230.00	66.00	
39	ACTON-SAN JACINTO	DU	66.00	12.00	
40	AEROJET-AZUSA	DU	66.00	12.00	

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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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	AFG-HESPERIA	DU	115.00	12.00	
2	AIR PRODUCTS-CARSON	DU	66.00	16.00	
3	ALDER-FOOTHILL	DU	66.00	12.00	
4	ALESSANDRO-SAN JACINTO	DU	115.00	33.00	
5	ALESSANDRO-SAN JACINTO	DU	115.00	12.00	
6	ALHAMBRA-MONTEBELLO	DU	66.00	16.00	
7	ALHAMBRA-MONTEBELLO	DU	66.00	4.00	
8	ALLEN-MONROVIA	DU	16.00	4.00	
9	ALON-COMPTON	DU	66.00	12.00	
10	AMADOR-EL MONTE	DU	66.00	16.00	
11	AMADOR-EL MONTE	DU	66.00	4.00	
12	AMALIA-MONTEBELLO	DU	16.00	4.00	
13	AMARGO-RIDGECREST	DU	33.00	4.00	
14	AMBOY-TWENTY-NINE PALMS	DU	33.00	12.00	
15	AMCO-TORRANCE	DU	66.00	12.00	
16	AMCO-TORRANCE	DU	12.00	4.00	
17	AMERON-ETIWANDA	DU	66.00	33.00	
18	ANAVERDE-LANCASTER	DU	66.00	12.00	
19	ANITA-MONROVIA	DU	66.00	16.00	
20	ANITA-MONROVIA	DU	66.00	4.00	
21	APL-LONG BEACH	DU	66.00	4.00	
22	APOLLO-HUNTINGTON BEACH	DU	66.00	12.00	
23	APPLE VALLEY-HI DESERT	DU	115.00	12.00	
24	AQUEDUCT-HI DESERT	DU	115.00	12.00	
25	ARCADIA-MONROVIA	DU	66.00	16.00	
26	ARCADIA-MONROVIA	DU	66.00	4.00	
27	ARCHIBALD-FOOTHILL	DU	66.00	12.00	
28	ARCHLINE-ONTARIO	DU	66.00	12.00	
29	ARCO-LONG BEACH	DU	66.00	12.00	
30	ARRO-SAN BERNARDINO	DU	33.00	4.00	
31	ARROWHEAD-ARROWHEAD	DU	115.00	33.00	
32	ARROWHEAD-ARROWHEAD	DU	33.00	12.00	
33	ARROYO-GLENDORA	DU	66.00	16.00	
34	ARROYO-GLENDORA	DU	16.00	4.00	
35	ASTRO-LONG BEACH	DU	66.00	12.00	
36	ATHENS-COMPTON	DU	16.00	4.00	
37	ATWOOD-FULLERTON	DU	66.00	12.00	
38	AULD-SAN JACINTO	DU	115.00	33.00	
39	AULD-SAN JACINTO	DU	115.00	12.00	
40	AZUSA-AZUSA	DU	66.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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	BAIN-MIRA LOMA	DU	66.00	12.00	
2	BAKER-HI DESERT	DU	115.00	33.00	
3	BAKER-HI DESERT	DU	115.00	12.00	
4	BANDINI-COMPTON	DU	66.00	16.00	
5	BANNING-INLAND	DU	115.00	33.00	
6	BARSTOW-HI DESERT	DU	33.00	12.00	
7	BARTOLO-WHITTIER	DU	12.00	4.00	
8	BASSETT-COVINA	DU	66.00	12.00	
9	BASTA-FULLERTON	DU	12.00	4.00	
10	BAYSIDE-HUNTINGTON BEACH	DU	66.00	12.00	
11	BEAUMONT-INLAND	DU	12.00	4.00	
12	BEDFORD-SANTA MONICA	DU	16.00	4.00	
13	BELDING-PALM SPRINGS	DU	33.00	4.00	
14	BELMONT-LONG BEACH	DU	12.00	4.00	
15	BELVEDERE-MONTEBELLO	DU	16.00	4.00	
16	BEVERLY-SANTA MONICA	DU	66.00	16.00	
17	BEVERLY-SANTA MONICA	DU	66.00	4.00	
18	BICKNELL-MONTEBELLO	DU	16.00	4.00	
19	BIXBY-LONG BEACH	DU	12.00	4.00	
20	BLACK MOUNTAIN-APPLE VALLEY	DU	115.00	4.00	
21	BLISS-TULARE	DU	66.00	12.00	
22	BLOOMINGTON-FOOTHILL	DU	66.00	12.00	
23	BLUFF COVE-REDONDO	DU	16.00	4.00	
24	BLYTHE CITY-BLYTHE	DU	33.00	12.00	
25	BLYTHE CITY-BLYTHE	DU	33.00	4.80	
26	BOLSA-HUNTINGTON BEACH	DU	66.00	12.00	
27	BOOST-LONG BEACH	DU	66.00	12.00	
28	BORREGO-EL TORO	DU	66.00	12.00	
29	BOTTLE-CABAZON	DU	115.00	4.00	
30	BOVINE-LONG BEACH	DU	66.00	12.00	
31	BOWL-LONG BEACH	DU	66.00	12.00	
32	BOWL-LONG BEACH	DU	66.00	4.00	
33	BOXWOOD-PORTERVILLE	DU	66.00	12.00	
34	BRADBURY-MONROVIA	DU	66.00	16.00	
35	BREA-FULLERTON	DU	66.00	12.00	
36	BREEZE-LANCASTER	DU	66.00	12.00	
37	BREW-IRWINDALE	DU	66.00	4.00	
38	BREWSTER-COMPTON	DU	16.00	4.00	
39	BRIDGE-REDONDO	DU	66.00	4.00	
40	BRIGHTON-REDONDO	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	BROADWAY-LONG BEACH	DU	66.00	12.00	
2	BROADWAY-LONG BEACH	DU	12.00	4.00	
3	BROOKHURST-HUNTINGTON BEACH	DU	66.00	12.00	
4	BROWNING-DELANO	DU	66.00	12.00	
5	BRYAN-SANTA ANA	DU	66.00	12.00	
6	BRYMAN-HI DESERT	DU	33.00	4.00	
7	BULLIS-COMPTON	DU	66.00	16.00	
8	BULLIS-COMPTON	DU	66.00	4.00	
9	BUNKER-SAN JACITO	DU	115.00	12.00	
10	BURNT MILL-LAKE ARROWHEAD	DU	33.00	12.00	
11	BURPIT-ORANGE	DU	66.00	4.00	
12	CABAZON-PALM SPRINGS	DU	33.00	12.00	
13	CABRILLO-EL TORO	DU	66.00	12.00	
14	CADY-HI DESERT	DU	33.00	12.00	
15	CAJALCO-PERRIS	DU	115.00	12.00	
16	CAL CEMENT-MOJAVE	DU	66.00	4.00	
17	CALCITY-CAL CITY	DU	33.00	12.00	
18	CALDEN-COMPTON	DU	66.00	16.00	
19	CALECTRIC-INLAND	DU	115.00	33.00	
20	CAMARILLO-VENTURA	DU	66.00	16.00	
21	CAMDEN-SANTA ANA	DU	66.00	12.00	
22	CAMERON-LONG BEACH	DU	66.00	12.00	
23	CANTIL-RIDGECREST	DU	33.00	12.00	
24	CANYON-FULLERTON	DU	66.00	12.00	
25	CANYON LAKE-SAN JACINTO	DU	33.00	12.00	
26	CAPITAN-SANTA BARBARA	DU	66.00	16.00	
27	CAPSULE-SAN BERNARDINO	DU	33.00	4.00	
28	CAPTIVE-DELANO	DU	66.00	12.00	
29	CARBOGEN-LONG BEACH	DU	66.00	12.00	
30	CARBONIC-CARSON	DU	66.00	12.00	
31	CARDIFF-INLAND	DU	66.00	12.00	
32	CARDIFF-INLAND	DU	66.00	4.00	
33	CARMENITA-WHITTIER	DU	66.00	12.00	
34	CARODEAN-TWENTY-NINE PALMS	DU	115.00	12.00	
35	CAROLINA-FULLERTON	DU	66.00	12.00	
36	CARPINTERIA-CARPINTERIA	DU	66.00	16.00	
37	CARSON-COMPTON	DU	66.00	16.00	
38	CASITAS-VENTURA	DU	66.00	16.00	
39	CATHEDRAL CITY-PALM SPRINGS	DU	33.00	4.80	
40	CEDARWOOD-HUNTINGTON BEACH	DU	12.00	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	CERTIFIED-LONG BEACH	DU	66.00	12.00	
2	CHANNEL ISLAND-TEHACHAPI	DU	66.00	16.00	
3	CHARMIN-OXNARD	DU	66.00	12.00	
4	CHARMIN-OXNARD	DU	66.00	4.00	
5	CHASE-ONTARIO	DU	66.00	12.00	
6	CHATHAM-VISALIA	DU	66.00	12.00	
7	CHATSWORTH-THOUSAND OAK	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	COLORADO-SANTA MONICA	DU	66.00	4.00	
19	COLOSSUS-VALENCIA	DU	66.00	16.00	
20	COLTON-FOOTHILL	DU	66.00	12.00	
21	COLTON CEMENT-COLTON	DU	66.00	12.00	
22	COLUMBINE-DELANO	DU	66.00	12.00	
23	COMPRESS-TORRANCE	DU	66.00	12.00	
24	COMPTON-COMPTON	DU	16.00	4.00	
25	CONCHO-PALM SPRINGS	DU	115.00	12.00	
26	CONVERSE FLATS-CAMP ANGELUS	DU	33.00	12.00	
27	CORNERS-LONG BEACH	DU	66.00	2.40	
28	CORNUTA-COMPTON	DU	66.00	12.00	
29	CORONA-ONTARIO	DU	66.00	33.00	
30	CORONA-ONTARIO	DU	66.00	12.00	
31	CORONA-ONTARIO	DU	33.00	4.00	
32	CORRECTION-TEHACHAPI	DU	66.00	12.00	
33	CORTEZ-COVINA	DU	66.00	12.00	
34	CORUM-LANCASTER	DU	66.00	12.00	
35	COSMIC-HAWTHORNE	DU	66.00	12.00	
36	COSO-LITTLE LAKE	DU	115.00	12.00	
37	COSTA MESA-HUNTINGTON BEACH	DU	12.00	4.00	
38	COTTONWOOD-HI DESERT	DU	115.00	33.00	
39	CRATER-THOUSAND OAK	DU	66.00	16.00	
40	CREST-REDONDO	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	CRESTMORE-RUBIDOUX	DU	66.00	4.00	
2	CROWN-HUNTINGTON BEACH	DU	66.00	12.00	
3	CUCAMONGA-FOOTHILL	DU	66.00	12.00	
4	CUDAHY-COMPTON	DU	66.00	16.00	
5	CUDAHY-COMPTON	DU	66.00	4.00	
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	CYBER-EL SEGUNDO	DU	66.00	12.00	
10	CRYCO-INDUSTRY	DU	66.00	13.80	
11	CYPRESS-FULLERTON	DU	66.00	12.00	
12	DAIRYMANS-TULARE	DU	66.00	12.00	
13	DAGGETT-BARSTOW	DU	33.00	4.00	
14	DAISY-LONG BEACH	DU	12.00	4.00	
15	DALTON-MONROVIA	DU	66.00	12.00	
16	DATABANK-CORONA	DU	66.00	12.00	
17	DAVIDSON CITY-LONG BEACH	DU	12.00	4.00	
18	DECLEZ-FOOTHILL	DU	66.00	12.00	
19	DECLEZ-FOOTHILL	DU	12.00	4.00	
20	DEFRAIN-BLYTHE	DU	33.00	12.00	
21	DEL MAR-EL SEGUNDO	DU	66.00	13.20	
22	DEL ROSA-INLAND	DU	66.00	12.00	
23	DEL SUR-LANCASTER	DU	66.00	12.00	
24	DELANO-DELANO	DU	66.00	12.00	
25	DELANO-DELANO	DU	66.00	4.00	
26	DESAL-SANTA BARBARA	DU	66.00	12.00	
27	DESERT OUTPOST-CATHEDRAL CITY	DU	33.00	12.00	
28	DIAMOND BAR-COVINA	DU	66.00	12.00	
29	DIEMER-YORBA LINDA	DU	66.00	4.00	
30	DIKE-LONG BEACH	DU	66.00	12.00	
31	DITMAR-REDONDO	DU	66.00	16.00	
32	DITMAR-REDONDO	DU	16.00	4.00	
33	DOCK-LONG BEACH	DU	66.00	25.00	
34	DOHENY-SANTA MONICA	DU	16.00	4.00	
35	DOMHILL-CARSON	DU	66.00	4.00	
36	DOUGLAS-EL SEGUNDO	DU	66.00	16.00	
37	DOUGOIL-PARAMOUNT	DU	66.00	12.00	
38	DOWNEY-WHITTIER	DU	12.00	4.00	
39	DOWNEY MED-WHITTIER	DU	66.00	12.00	
40	DOWNS-RIDGECREST	DU	115.00	12.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	DUARTE-MONROVIA	DU	16.00	4.00	
2	DUNES-BLYTHE	DU	33.00	12.00	
3	DUNN SIDING-HI DESERT	DU	115.00	12.00	
4	EARLIMART-DELANO	DU	66.00	12.00	
5	EAST BARSTOW-HI DESERT	DU	33.00	4.00	
6	EATON-MONROVIA	DU	66.00	16.00	
7	EDINGER-SANTA ANA	DU	12.00	4.00	
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 SOBRANTE-ONTARIO	DU	33.00	12.00	
12	ELCANS-VISALIA	DU	66.00	12.00	
13	ELIZABETH LAKE-VENTURA	DU	66.00	16.00	
14	ELSINORE-SAN JACINTO	DU	115.00	33.00	
15	ELSINORE-SAN JACINTO	DU	115.00	12.00	
16	ELY-FULLERTON	DU	66.00	12.00	
17	ERIC-LONG BEACH	DU	66.00	12.00	
18	ESTERO-VENTURA	DU	66.00	16.00	
19	ESTRELLA-EL TORO	DU	66.00	12.00	
20	EUCLID-ONTARIO	DU	12.00	4.00	
21	FAIR OAKS-MONROVIA	DU	16.00	4.00	
22	FAIRFAX-LOS ANGELES	DU	66.00	16.00	
23	FAIRFAX-LOS ANGELES	DU	16.00	4.00	
24	FAIRVIEW-SANTA ANA	DU	66.00	12.00	
25	FARRELL-PALM SPRINGS	DU	115.00	12.00	
26	FEDERALGEN-COMMERCE	DU	66.00	12.00	
27	FELTON-INGLEWOOD	DU	66.00	16.00	
28	FELTON-INGLEWOOD	DU	16.00	4.00	
29	FERNWOOD-COMPTON	DU	66.00	16.00	
30	FIBRE-RIVERSIDE	DU	66.00	4.00	
31	FILLMORE-VENTURA	DU	66.00	16.00	
32	FIREHOUSE-ONTARIO	DU	66.00	12.00	
33	FLORADAY-WHITTIER	DU	12.00	4.00	
34	FOGARTY-LITTLE LAKE	DU	115.00	12.00	
35	FOREST HOME-INLAND	DU	33.00	2.40	
36	FORGE-RANCHO CUCAMONGA	DU	66.00	12.00	
37	FORT IRWIN-FORT IRWIN	DU	33.00	12.00	
38	FRANCIS-ONTARIO	DU	66.00	12.00	
39	FRAZIER PARK-LANCASTER	DU	66.00	12.00	
40	FREMONT-COMPTON	DU	66.00	16.00	

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1	FREMONT-COMPTON	DU	16.00	4.00	
2	FRUITLAND-COMPTON	DU	66.00	16.00	
3	FRUITLAND-COMPTON	DU	66.00	4.00	
4	FUEL-LONG BEACH	DU	66.00	4.00	
5	FULLERTON-FULLERTON	DU	66.00	12.00	
6	FULLERTON-FULLERTON	DU	66.00	4.00	
7	GAGE-COMPTON	DU	16.00	4.00	
8	GALAXY-MANHATTAN BEACH	DU	66.00	12.00	
9	GALAXY-MANHATTAN BEACH	DU	66.00	4.00	
10	GALE-HI DESERT	DU	115.00	33.00	
11	GALLATIN-WHITTIER	DU	66.00	12.00	
12	GANESHA-COVINA	DU	66.00	12.00	
13	GANESHA-COVINA	DU	12.00	4.00	
14	GARFIELD-EL MONTE	DU	66.00	4.00	
15	GARNET-PALM SPRINGS	DU	115.00	33.00	
16	GARNET-PALM SPRINGS	DU	33.00	12.00	
17	GARVEY-MONTEBELLO	DU	16.00	4.00	
18	GATX-CARSON	DU	66.00	12.00	
19	GAVILAN-SAN JACINTO	DU	33.00	12.00	
20	GAVIOTA-SANTA BARBARA	DU	66.00	16.00	
21	GENAMIC-RANCHO CUCAMONGA	DU	66.00	12.00	
22	GEORGE A.F.B.-ADELANTO	DU	33.00	4.00	
23	GETTY-VENTURA	DU	66.00	16.00	
24	GILBERT-FULLERTON	DU	66.00	12.00	
25	GISLER-HUNTINGTON BEACH	DU	66.00	12.00	
26	GLEN AVON-ONTARIO	DU	66.00	12.00	
27	GLEN IVY-GLEN IVY HOT	DU	33.00	12.00	
28	GLENNVILLE-DELANO	DU	66.00	12.00	
29	GOLDSTONE-BARSTOW	DU	33.00	12.00	
30	GOLDTOWN-LANCASTER	DU	66.00	12.00	
31	GONZALES-VENTURA	DU	66.00	16.00	
32	GORMAN-LANCASTER	DU	66.00	12.00	
33	GOSHEN-VISALIA	DU	66.00	12.00	
34	GRAHAM-COMPTON	DU	16.00	4.00	
35	GRANADA-MONTEBELLO	DU	16.00	4.00	
36	GREAT LAKES-ROSAMOND	DU	66.00	12.00	
37	GREENHORN-DELANO	DU	66.00	2.40	
38	GREENING-LONG BEACH	DU	66.00	12.00	
39	HAAGEN-TULARE	DU	66.00	4.00	
40	HAMILTON-HUNTINGTON 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	HANFORD-HANFORD	DU	66.00	4.00	
2	HANJIN-LONG BEACH	DU	66.00	12.00	
3	HARVARD-HI DESERT	DU	33.00	12.00	
4	HASKELL-SAN FERNANDO	DU	66.00	16.00	
5	HATHAWAY-LONG BEACH	DU	66.00	12.00	
6	HATHAWAY-LONG BEACH	DU	66.00	4.00	
7	HAVASU-BLYTHE	DU	66.00	16.00	
8	HAVEDA-REDONDO	DU	16.00	4.00	
9	HAVILAH-KERNVILLE	DU	66.00	12.00	
10	HEDDA-LONG BEACH	DU	12.00	4.00	
11	HELENDALE-HI DESERT	DU	33.00	12.00	
12	HELIJET-PALMDALE	DU	66.00	12.00	
13	HELIJET-PALMDALE	DU	12.00	4.00	
14	HEMET-SAN JACINTO	DU	33.00	12.00	
15	HESPERIA-HI DESERT	DU	115.00	12.00	
16	HI DESERT-TWENTY-NINE PALMS	DU	115.00	33.00	
17	HI DESERT-TWENTY-NINE PALMS	DU	34.50	24.94	
18	HIGHLAND-INLAND	DU	66.00	12.00	
19	HILLGEN-CITY OF INDUSTRY	DU	66.00	12.00	
20	HINKLEY-HI DESERT	DU	33.00	12.00	
21	HOLGATE-BORON	DU	33.00	12.00	
22	HOLIDAY-PALM SPRINGS	DU	33.00	4.00	
23	HOMART-INLAND	DU	115.00	12.00	
24	HOPEFUL-DUARTE	DU	66.00	12.00	
25	HOWARD-INGLEWOOD	DU	66.00	4.00	
26	HOYT-EL MONTE	DU	16.00	4.00	
27	HUGHESAIR-EL SEGUNDO	DU	66.00	12.00	
28	HUGHTRON-TORRANCE	DU	66.00	4.00	
29	HUNTINGTON PARK-COMPTON	DU	16.00	4.00	
30	HUSTON-ARROWHEAD	DU	33.00	12.00	
31	HUSTON-ARROWHEAD	DU	33.00	2.40	
32	IMPERIAL-WHITTIER	DU	66.00	12.00	
33	IMPERIAL-WHITTIER	DU	66.00	4.00	
34	INDIAN WELLS-PALM SPRINGS	DU	115.00	12.00	
35	INDUSTRY-COVINA	DU	66.00	12.00	
36	INGLEWOOD-INGLEWOOD	DU	66.00	16.00	
37	INGLEWOOD-INGLEWOOD	DU	66.00	4.00	
38	INJECTION-LONG BEACH	DU	66.00	12.00	
39	INLAND-ONTARIO	DU	66.00	12.00	
40	INYOKERN-RIDGECREST	DU	115.00	33.00	

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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	INYOKERN-RIDGECREST	DU	33.00	12.00	
2	INYOKERN TOWN-RIDGECREST	DU	33.00	4.80	
3	IRON MT. SCE-DESERT CENTER	DU	16.00	6.90	
4	IRVINE-EL TORO	DU	66.00	12.00	
5	ISABELLA-KERNVILLE	DU	66.00	12.00	
6	ISLA VISTA-SANTA BARBARA	DU	66.00	16.00	
7	IVAR-MONTEBELLO	DU	16.00	4.00	
8	IVYGLEN-ONTARIO	DU	115.00	12.00	
9	JEFFERSON-ONTARIO	DU	66.00	12.00	
10	JERSEY-COMPTON	DU	66.00	16.00	
11	JOSHUA TREE-TWENTY-NINE PALMS	DU	33.00	12.00	
12	KEMPSTER-FOOTHILL	DU	33.00	4.00	
13	KERNVILLE-KERNVILLE	DU	66.00	16.00	
14	KIMBALL-CHINO	DU	66.00	12.00	
15	LA CANADA-MONROVIA	DU	66.00	16.00	
16	LA CANADA-MONROVIA	DU	16.00	4.00	
17	LA HABRA-FULLERTON	DU	66.00	12.00	
18	LA MIRADA-WHITTIER	DU	66.00	12.00	
19	LANPRI-LANCASTER	DU	66.00	12.00	
20	LA PALMA-FULLERTON	DU	66.00	12.00	
21	LA VETA-SANTA ANA	DU	66.00	12.00	
22	LAFAYETTE-HUNTINGTON BEACH	DU	66.00	12.00	
23	LAKEVIEW-NUEVO	DU	115.00	12.00	
24	LAKEWOOD-LONG BEACH	DU	66.00	4.00	
25	LAMPSON-SANTA ANA	DU	66.00	12.00	
26	LANCASTER-LANCASTER	DU	66.00	12.00	
27	LANCASTER-LANCASTER	DU	12.00	4.00	
28	LANDING-BLYTHE	DU	66.00	16.00	
29	LARDER-LONG BEACH	DU	12.00	4.00	
30	LARK ELLEN-COVINA	DU	66.00	12.00	
31	LAS LOMAS-IRVINE	DU	66.00	12.00	
32	LATIGO-THOUSAND OAK	DU	66.00	16.00	
33	LAUREL-TULARE	DU	66.00	12.00	
34	LAWNDALE-INGLEWOOD	DU	16.00	4.00	
35	LAYFAIR-COVINA	DU	66.00	12.00	
36	LAYFAIR-COVINA	DU	66.00	4.00	
37	LEATHERNECK-TWENTY-NINE PALMS	DU	115.00	34.50	
38	LEHMAN-OXNARD	DU	66.00	12.00	
39	LEMON COVE-VISALIA	DU	66.00	12.00	
40	LENNOX-INGLEWOOD	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	LENNOX-INGLEWOOD	DU	16.00	4.00	
2	LEVY-VENTURA	DU	66.00	16.00	
3	LIBERTY-VISALIA	DU	66.00	12.00	
4	LIMESTONE-EL TORO	DU	66.00	12.00	
5	LINDEN-LONG BEACH	DU	12.00	4.00	
6	LINDSAY-PORTERVILLE	DU	66.00	12.00	
7	LINDSAY-PORTERVILLE	DU	66.00	4.00	
8	LIQUID-IRWINDALE	DU	66.00	4.00	
9	LITTLE ROCK-PALMDALE	DU	66.00	12.00	
10	LIVE OAK-COVINA	DU	66.00	12.00	
11	LOCKHEED-SAUGUS	DU	66.00	16.00	
12	LOCUST-LONG BEACH	DU	12.00	4.00	
13	LONGDON-COMPTON	DU	16.00	4.00	
14	LORAINE-LANCASTER	DU	66.00	12.00	
15	LOS CERRITOS-LONG BEACH	DU	66.00	12.00	
16	LOS CERRITOS-LONG BEACH	DU	12.00	4.00	
17	LOSULFUR-EL SEGUNDO	DU	66.00	13.20	
18	LUCAS-LONG BEACH	DU	66.00	12.00	
19	LUCAS-LONG BEACH	DU	66.00	4.00	
20	LUCERNE-HI DESERT	DU	33.00	12.00	
21	LUNADA-REDONDO	DU	16.00	4.00	
22	LYNWOOD-COMPTON	DU	66.00	4.00	
23	MACARTHUR-HUNTINGTON BEACH	DU	66.00	12.00	
24	MACNEIL-BURBANK	DU	66.00	12.00	
25	MADRID-REDONDO	DU	16.00	4.00	
26	MALIBU-THOUSAND OAK	DU	66.00	16.00	
27	MANHATTAN-REDONDO	DU	16.00	4.00	
28	MARASCHINO-INLAND	DU	115.00	12.00	
29	MARINE-SANTA MONICA	DU	66.00	16.00	
30	MARION-FULLERTON	DU	66.00	12.00	
31	MARIPOSA-DELANO	DU	66.00	12.00	
32	MARYMOUNT-REDONDO	DU	66.00	16.00	
33	MASCOT-HANFORD	DU	66.00	12.00	
34	MAXWELL-SAN JACINTO	DU	115.00	12.00	
35	MAYBERRY-SAN JACINTO	DU	115.00	12.00	
36	MAYFLOWER-MONROVIA	DU	16.00	4.00	
37	MENTONE-INLAND	DU	115.00	12.00	
38	MERCED-COVINA	DU	66.00	12.00	
39	MICHILLINDA-MONROVIA	DU	16.00	4.00	
40	MILITARY-TEMECULA	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	MILLIKEN-INLAND	DU	66.00	12.00	
2	MINNEOLA-HI DESERT	DU	33.00	12.00	
3	MISSILE-POINT MUGU	DU	66.00	16.00	
4	MOBILE SUBSTATIONS-TORRANCE	DU	115.00	33.00	
5	MOBILE SUBSTATIONS-TORRANCE	DU	66.00	2.40	
6	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	4.00	
7	MOBILE SUBSTATIONS-TORRANCE	DU	33.00	2.40	
8	MOBILE SUBSTATIONS-TORRANCE	DU	16.00	2.40	
9	MOBILE SUBSTATIONS-TORRANCE	DU	12.00	2.40	
10	MOBILOIL-TORRANCE	DU	66.00	12.00	
11	MOBILOIL-TORRANCE	DU	12.00	2.40	
12	MOBILOIL-TORRANCE	DU	12.00	0.48	
13	MODENA-SANTA ANA	DU	66.00	12.00	
14	MODOC-SANTA BARBARA	DU	16.00	4.00	
15	MONETA-REDONDO	DU	16.00	4.00	
16	MONOLITH-LANCASTER	DU	66.00	12.00	
17	MONROVIA-MONROVIA	DU	16.00	4.00	
18	MONTECITO-SANTA BARBARA	DU	16.00	4.00	
19	MOOG-TORRANCE	DU	66.00	12.00	
20	MORAGA-TEMECULA	DU	115.00	12.00	
21	MORENO-MORENO VALLEY	DU	115.00	12.00	
22	MORNINGSIDE-INGLEWOOD	DU	16.00	4.00	
23	MORRO-EL TORO	DU	66.00	12.00	
24	MOULTON-EL TORO	DU	66.00	12.00	
25	MOUNTAIN PASS-HI DESERT	DU	115.00	33.00	
26	MOUNTAIN PASS-HI DESERT	DU	33.00	12.00	
27	MOVIE-CULVER CITY	DU	66.00	16.00	
28	MT. VERNON-INLAND	DU	33.00	4.00	
29	MURPHY-WHITTIER	DU	66.00	12.00	
30	MURRIETTA 2-SAN JACINTO	DU	33.00	12.00	
31	MUSCOY-INLAND	DU	33.00	4.00	
32	NAOMI-COMPTON	DU	16.00	4.00	
33	NAPLES-LONG BEACH	DU	12.00	4.00	
34	NAROD-ONTARIO	DU	66.00	12.00	
35	NARROWS-WHITTIER	DU	66.00	12.00	
36	NATURAL-TWENTY-NINE PALMS	DU	66.00	12.00	
37	NAVY MOLE-LONG BEACH	DU	66.00	12.00	
38	NIAGRA-RIALTO	DU	66.00	12.00	
39	NEENACH-LANCASTER	DU	66.00	12.00	
40	NELSON-SAN JACINTO	DU	115.00	33.00	

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1	NELSON-SAN JACINTO	DU	115.00	12.00	
2	NEPTUNE-LONG BEACH	DU	66.00	12.00	
3	NEPTUNE-LONG BEACH	DU	66.00	4.00	
4	NEWBURY-THOUSAND OAK	DU	66.00	16.00	
5	NEWCOMB-SAN JACINTO	DU	115.00	12.00	
6	NEWHALL-SAN FERNANDO	DU	66.00	16.00	
7	NEWMARK-MONTEBELLO	DU	66.00	16.00	
8	NEWMARK-MONTEBELLO	DU	66.00	4.00	
9	NIAGARA-RIALTO	DU	66.00	12.00	
10	NIGUEL-EL TORO	DU	66.00	12.00	
11	NIGUEL-EL TORO	DU	66.00	4.00	
12	NOGALES-COVINA	DU	66.00	12.00	
13	NOLA-COMPTON	DU	66.00	16.00	
14	NORSEAL-SEAL BEACH	DU	66.00	12.00	
15	NORTH INTAKE-BLYTHE	DU	33.00	12.00	
16	NORTH MUROC-RIDGECREST	DU	33.00	12.00	
17	NORTH OAKS-SAN FERNANDO	DU	66.00	16.00	
18	NORTHROP-HAWTHORNE	DU	66.00	4.00	
19	NORTHWIND-LANCASTER	DU	66.00	12.00	
20	NORWELD-BREA	DU	66.00	12.00	
21	NUGGET-TWENTY-NINE PALMS	DU	34.90	24.90	
22	OAK GROVE-VISALIA	DU	66.00	12.00	
23	OAK PARK-THOUSAND OAK	DU	66.00	16.00	
24	OASIS-LANCASTER	DU	66.00	12.00	
25	OCEAN PARK-SANTA MONICA	DU	16.00	4.00	
26	OCEANVIEW-HUNTINGTON BEACH	DU	66.00	12.00	
27	OCTOL-TULARE	DU	66.00	12.00	
28	OJAI-VENTURA	DU	66.00	16.00	
29	OLDFIELD-LONG BEACH	DU	12.00	4.00	
30	OLIVE LAKE-BLYTHE	DU	33.00	12.00	
31	OLYMPIC-SANTA MONICA	DU	16.00	4.00	
32	ONEILL-RANCHO SANTA	DU	66.00	12.00	
33	ONSHORE-ELLWOOD	DU	66.00	12.00	
34	ORANGE-SANTA ANA	DU	66.00	12.00	
35	ORCOGEN-HUNTINGTON BEACH	DU	66.00	12.00	
36	ORCOSAN-FOUNTAIN VALLEY	DU	66.00	12.00	
37	ORDWAY-HI DESERT	DU	33.00	12.00	
38	ORO GRANDE-HI DESERT	DU	33.00	12.00	
39	ORTEGA-SANTA BARBARA	DU	66.00	33.00	2.40
40	PACLINE-CARSON	DU	66.00	2.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PALM CANYON-PALM SPRINGS	DU	33.00	12.00	
2	PALM CANYON-PALM SPRINGS	DU	33.00	4.00	
3	PALM SPRINGS-PALM SPRINGS	DU	33.00	4.00	
4	PALM VILLAGE-PALM SPRINGS	DU	33.00	12.00	
5	PALM VILLAGE-PALM SPRINGS	DU	33.00	4.80	
6	PALMDALE-LANCASTER	DU	66.00	12.00	
7	PALOS VERDES-REDONDO	DU	16.00	4.00	
8	PAPER-FULLERTON	DU	66.00	4.00	
9	PARKWOOD-FULLERTON	DU	66.00	12.00	
10	PASSONS-WHITTIER	DU	66.00	12.00	
11	PAUBA-SAN JACINTO	DU	115.00	12.00	
12	PAULARINO-HUNTINGTON BEACH	DU	12.00	4.00	
13	PEARL-SANTA MONICA	DU	16.00	4.00	
14	PECHANGA-SAN JACINTO	DU	115.00	33.00	
15	PECHANGA-SAN JACINTO	DU	115.00	12.00	
16	PEDLEY-ONTARIO	DU	66.00	12.00	
17	PEERLESS-RIDGECREST	DU	33.00	12.00	
18	PEPPER-INLAND	DU	115.00	12.00	
19	PEREZ-ONTARIO	DU	33.00	4.00	
20	PERRY-REDONDO	DU	16.00	4.00	
21	PEYTON-ONTARIO	DU	66.00	12.00	
22	PHARMACY-THOUSAND OAK	DU	66.00	16.00	
23	PHELAN-HI DESERT	DU	115.00	33.00	
24	PHELAN-HI DESERT	DU	115.00	12.00	
25	PICO-LONG BEACH	DU	66.00	12.00	
26	PIER-LONG BEACH	DU	66.00	12.00	
27	PIERPONT-VENTURA	DU	16.00	4.00	
28	PIONEER-WHITTIER	DU	66.00	12.00	
29	PIONEER-WHITTIER	DU	12.00	4.00	
30	PIPE-ETIWANDA	DU	66.00	12.00	
31	PITCHGEN-SAUGUS	DU	66.00	12.00	
32	PIUTE-LANCASTER	DU	66.00	12.00	
33	PIXLEY-DELANO	DU	66.00	12.00	
34	PLACENTIA-FULLERTON	DU	66.00	12.00	
35	PLASTER-SOUTH GATE	DU	66.00	2.40	
36	PLASTIC-CHINO	DU	66.00	12.00	
37	PLAYA-SANTA BARBARA	DU	16.00	4.00	
38	POLARIS-EL SEGUNDO	DU	66.00	4.00	
39	POLARIS-EL SEGUNDO	DU	16.00	4.00	
40	POMONA-COVINA	DU	12.00	4.00	

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1	POPLAR-PORTERVILLE	DU	66.00	12.00	
2	PORTERVILLE-PORTERVILLE	DU	66.00	12.00	
3	PORTERVILLE-PORTERVILLE	DU	66.00	4.00	
4	POTRERO-THOUSAND OAK	DU	66.00	16.00	
5	PROCESS-LONG BEACH	DU	66.00	12.00	
6	PROCGEN-OXNARD	DU	66.00	12.00	
7	PROCTOR-COMPTON	DU	66.00	12.00	
8	PROTEIN-TULARE	DU	66.00	12.00	
9	PUENTE-COVINA	DU	66.00	12.00	
10	PUREWATER-REDLANDS	DU	115.00	4.00	
11	QUARTZ HILL-LANCASTER	DU	66.00	12.00	
12	QUINN-DELANO	DU	66.00	12.00	
13	RAILROAD-COVINA	DU	66.00	12.00	
14	RALPHS-COMPTON	DU	66.00	4.00	
15	RAMONA-MONTEBELLO	DU	66.00	4.00	
16	RANCHO-HI DESERT	DU	33.00	12.00	
17	RANDALL-FOOTHILL	DU	66.00	12.00	
18	RANDOLPH-COMPTON	DU	66.00	16.00	
19	RANDSBURG-RIDGECREST	DU	115.00	33.00	
20	RAVENDALE-MONTEBELLO	DU	66.00	16.00	
21	RAVENDALE-MONTEBELLO	DU	66.00	4.00	
22	RECOVERY-HUNTINGTON BEACH	DU	66.00	12.00	
23	RECTIFIER-TEMECULA	DU	115.00	33.00	
24	REDLANDS-INLAND	DU	66.00	12.00	
25	REDLANDS-INLAND	DU	66.00	4.00	
26	REDMAN-LANCASTER	DU	66.00	12.00	
27	REDONDO-REDONDO	DU	16.00	4.00	
28	REDUCTION-ETIWANDA	DU	66.00	12.00	
29	REDUCTION-ETIWANDA	DU	66.00	4.00	
30	REFINERY-CARSON	DU	66.00	12.00	
31	REFUSE-COMMERCE	DU	66.00	12.00	
32	RENO-INDUSTRY	DU	66.00	4.00	
33	REPETTO-MONTEBELLO	DU	66.00	16.00	
34	REPETTO-MONTEBELLO	DU	66.00	4.00	
35	RIALTO-FOOTHILL	DU	33.00	12.00	
36	RIALTO-FOOTHILL	DU	33.00	4.00	
37	RIDGECREST-RIDGECREST	DU	33.00	4.80	
38	RINGMILL-PARAMOUNT	DU	66.00	4.00	
39	RIPLEY-BLYTHE	DU	33.00	12.00	
40	RITEAID-LANCASTER	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.
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	RITTER RANCH-PALMDALE	DU	66.00	12.00	
2	RIVERA-WHITTIER	DU	12.00	4.00	
3	RIVERTEX-ORO GRANDE	DU	115.00	13.80	
4	RIVERWAY-VISALIA	DU	66.00	12.00	
5	ROADWAY-HI DESERT	DU	115.00	12.00	
6	ROCKAIR-PALMDALE	DU	66.00	12.00	
7	ROCKET TEST-BORON	DU	115.00	33.00	
8	ROLLING HILLS-REDONDO	DU	66.00	16.00	
9	ROLLING HILLS-REDONDO	DU	66.00	4.00	
10	ROSAMOND-LANCASTER	DU	66.00	16.00	
11	ROSAMOND-LANCASTER	DU	66.00	12.00	
12	ROSECRANS-EL SEGUNDO	DU	66.00	16.00	
13	ROSEMEAD-MONTEBELLO	DU	66.00	16.00	
14	ROYAL-SIMI VALLEY	DU	66.00	16.00	
15	RUBIDOUX-RUBIDOUX	DU	33.00	12.00	
16	RUBIDOUX-RUBIDOUX	DU	33.00	4.00	
17	RUNNING SPRINGS-ARROWHEAD	DU	33.00	12.00	
18	RUSH-MONTEBELLO	DU	66.00	16.00	
19	SAN ANTONIO-COVINA	DU	66.00	12.00	
20	SAN DIMAS-COVINA	DU	66.00	12.00	
21	SAN FERNANDO-SAN FERNANDO	DU	66.00	16.00	
22	SAN GABRIEL-MONTEBELLO	DU	66.00	4.00	
23	SAN MARCOS-SANTA BARBARA	DU	66.00	16.00	
24	SAN MARINO-MONROVIA	DU	16.00	4.00	
25	SAN MIGUEL-VENTURA	DU	66.00	16.00	
26	SAN VICENTE-SANTA MONICA	DU	16.00	4.00	
27	SANGAR-MONROVIA	DU	16.00	4.00	
28	SANIGEN-WALNUT	DU	66.00	12.00	
29	SANTA BARBARA-SANTA BARBARA	DU	66.00	16.00	
30	SANTA BARBARA-SANTA BARBARA	DU	66.00	4.00	
31	SANTA FE SPRINGS-WHITTIER	DU	66.00	12.00	
32	SANTA MONICA-SANTA MONICA	DU	66.00	16.00	
33	SANTA MONICA-SANTA MONICA	DU	66.00	4.00	
34	SANTA ROSA-PALM SPRINGS	DU	115.00	33.00	
35	SANTA ROSA-PALM SPRINGS	DU	115.00	12.00	
36	SANTA SUSANA-THOUSAND OAK	DU	66.00	16.00	
37	SANTEE-INDUSTRY	DU	66.00	12.00	
38	SATICOY-VENTURA	DU	66.00	16.00	
39	SAVAGE-HESPERIA	DU	115.00	12.00	
40	SAWTELLE-SANTA MONICA	DU	66.00	16.00	

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Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

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	SEABRIGHT-LONG BEACH	DU	66.00	12.00	
2	SEARLES-RIDGECREST	DU	115.00	33.00	
3	SECOND AVENUE-BLYTHE	DU	33.00	12.00	
4	SEPULVEDA-INGLEWOOD	DU	66.00	16.00	
5	SEPULVEDA-INGLEWOOD	DU	16.00	4.00	
6	SERRFGEN-LONG BEACH	DU	66.00	12.00	
7	SERVER-EL SEGUNDO	DU	66.00	16.00	
8	SHANDIN-INLAND	DU	115.00	12.00	
9	SHAWNEE-HUNTINGTON BEACH	DU	66.00	12.00	
10	SHELLSOM-SOMIS	DU	66.00	2.40	
11	SHELLWATT-CARSON	DU	66.00	12.00	
12	SHIP-LONG BEACH	DU	66.00	12.00	
13	SHRED-SOUTHGATE	DU	66.00	12.00	
14	SHULTZ-SOUTH GATE	DU	66.00	16.00	
15	SHUTTLE-LANCASTER	DU	66.00	12.00	
16	SIERRA MADRE-MONROVIA	DU	16.00	4.00	
17	SIGGEN-NORWALK	DU	66.00	12.00	
18	SIGNAL HILL-LONG BEACH	DU	66.00	12.00	
19	SIGNAL HILL-LONG BEACH	DU	12.00	4.00	
20	SILVER SPUR-PALM SPRINGS	DU	33.00	12.00	
21	SIMPSON PAPER-FULLERTON	DU	66.00	4.00	
22	SIXTEENTH STREET-INLAND	DU	33.00	12.00	
23	SKINWATER-WINCHESTER	DU	33.00	4.00	
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	SOPIPE-INDUSTRY	DU	66.00	4.00	
34	SOQUEL-CHINO HILLS	DU	66.00	12.00	
35	SOUTH GATE-COMPTON	DU	16.00	4.00	
36	SOUTHBASE-E.A.F.B.	DU	115.00	33.00	
37	SPACE-REDONDO BEACH	DU	66.00	4.00	
38	SPONGE-PICO RIVERA	DU	66.00	2.40	
39	STADIUM-LONG BEACH	DU	66.00	12.00	
40	STADLER-SAN JACINTO	DU	115.00	12.00	

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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	STANHILL-INGLEWOOD	DU	66.00	12.00	
2	STATE STREET-LONG BEACH	DU	66.00	12.00	
3	STENT-TEMECULA	DU	115.00	12.00	
4	STETSON-SAN JACINTO	DU	115.00	12.00	
5	STEVEDORE-LONG BEACH	DU	66.00	12.00	
6	STEWART-WHITTIER	DU	66.00	12.00	
7	STODDARD-INLAND	DU	33.00	4.00	
8	STRATHMORE-PORTERVILLE	DU	66.00	12.00	
9	SULLIVAN-SANTA ANA	DU	66.00	12.00	
10	SULLIVAN-SANTA ANA	DU	66.00	4.00	
11	SUN CITY-SAN JACINTO	DU	115.00	12.00	
12	SUNNY DUNES-PALM SPRINGS	DU	33.00	4.00	
13	SUNNYHILLS-FULLERTON	DU	66.00	12.00	
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 OAK	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 OAK	DU	66.00	16.00	
30	THREE RIVERS-VISALIA	DU	66.00	12.00	
31	THRIVE-FONTANA	DU	66.00	12.00	
32	THRUST-CHATSWORTH	DU	66.00	4.00	
33	THUMS ISLAND ABCD-ISLAND GRISSOM-LONG BEACH	DU	66.00	4.00	
34	THUNDERBIRD-PALM SPRINGS	DU	33.00	4.80	
35	TIDELANDS-LONG BEACH	DU	66.00	12.00	
36	TIEFORT-HI DESERT	DU	115.00	33.00	
37	TIMBERWINE-BIG CREEK	DU	33.00	12.00	
38	TIMOTEO-INLAND	DU	66.00	12.00	
39	TIPPECANOE-INLAND	DU	12.00	4.00	
40	TIPTON-TULARE	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	TOPANGA-THOUSAND OAK	DU	16.00	4.00	
2	TOPAZ-REDONDO	DU	66.00	4.00	
3	TORRANCE-REDONDO	DU	66.00	16.00	
4	TORREY-PIRU	DU	66.00	16.00	
5	TORTILLA-HI DESERT	DU	115.00	33.00	
6	TORTILLA-HI DESERT	DU	115.00	12.00	
7	TOYOTA-LONG BEACH	DU	66.00	12.00	
8	TRASK-SANTA ANA	DU	66.00	12.00	
9	TRITON-RANCHO PALO VERDE	DU	115.00	12.00	
10	TRONA-RIDGECREST	DU	33.00	12.00	
11	TROPHY-COVINA	DU	66.00	12.00	
12	TULARE-TULARE	DU	66.00	12.00	
13	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	12.00	
14	TWENTYNINE PALMS-TWENTY-NINE PALMS	DU	33.00	4.80	
15	UNIOIL-OXNARD	DU	66.00	16.00	
16	UNIVERSAL-UNIVERSAL CITY	DU	66.00	12.00	
17	UPLAND-FOOTHILL	DU	66.00	12.00	
18	UPLAND-FOOTHILL	DU	66.00	4.00	
19	VAIL-MONTEBELLO	DU	66.00	16.00	
20	VALDEZ-THOUSAND OAK	DU	66.00	16.00	
21	VEGAS-SANTA BARBARA	DU	66.00	16.00	
22	VENICE HILL-VISALIA	DU	66.00	12.00	
23	VENIDA-VISALIA	DU	66.00	12.00	
24	VERA-SANTA ANA	DU	66.00	12.00	
25	VERDANT-BLYTHE	DU	33.00	12.00	
26	VICTORIA-REDONDO	DU	66.00	16.00	
27	VICTORVILLE-HI DESERT	DU	33.00	12.00	
28	VICTORVILLE-HI DESERT	DU	33.00	4.00	
29	VISALIA-VISALIA	DU	66.00	12.00	
30	WABASH-MONTEBELLO	DU	66.00	12.00	
31	WAKEFIELD-VENTURA	DU	66.00	16.00	
32	WALKER BASIN-KERNVILLE	DU	66.00	12.00	
33	WALTERIA-REDONDO	DU	66.00	16.00	
34	WALTERIA-REDONDO	DU	66.00	4.00	
35	WASHINGTON-SANTA ANA	DU	66.00	12.00	
36	WASTEWATER-OXNARD	DU	66.00	16.00	
37	WATSON-COMPTON	DU	66.00	12.00	
38	WAVE-HUNTINGTON BEACH	DU	66.00	12.00	
39	WELDON-KERNVILLE	DU	66.00	12.00	
40	WESBASIN-EL SEGUNDO	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	WEST BARSTOW-HI DESERT	DU	33.00	4.00	
2	WEST RIVERSIDE-ONTARIO	DU	33.00	12.00	
3	WESTEX-SIGNAL HILL	DU	66.00	12.00	
4	WESTHILL-EL SEGUNDO	DU	66.00	16.00	
5	WESTPAC-GORMAN	DU	66.00	4.00	
6	WEYMOUTH-LA VERNE	DU	66.00	4.00	
7	WHARF-LONG BEACH	DU	66.00	12.00	
8	WHEATLAND-DELANO	DU	66.00	12.00	
9	WHIPPLE-BLYTHE	DU	66.00	33.00	
10	WHITEWATER-PALM SPRINGS	DU	33.00	4.00	
11	WILLAMETTE-OXNARD	DU	66.00	12.00	
12	WILSONA-LANCASTER	DU	66.00	12.00	
13	WIMBLEDON-FOOTHILL	DU	66.00	12.00	
14	WINDSOR HILLS-INGLEWOOD	DU	66.00	16.00	
15	WINDSOR HILLS-INGLEWOOD	DU	16.00	4.00	
16	WOODRUFF-COMPTON	DU	12.00	4.00	
17	WOODVILLE-PORTERVILLE	DU	66.00	12.00	
18	WRIGHTWOOD-HI DESERT	DU	33.00	12.00	
19	WRIGHTWOOD-HI DESERT	DU	12.00	2.40	
20	YERMO-HI DESERT	DU	33.00	12.00	
21	YORBA LINDA-FULLERTON	DU	66.00	12.00	
22	YUCAIPA-INLAND	DU	66.00	12.00	
23	YUCCA-TWENTY-NINE PALMS	DU	115.00	12.00	
24	YUKON-INGLEWOOD	DU	66.00	16.00	
25	YUKON-INGLEWOOD	DU	66.00	4.00	
26	ZANJA-YUCAIPA	DU	115.00	33.00	
27					
28					
29	Note:				
30	DA - Distribution Attended				
31	DU - Distribution Unattended				
32	TA - Transmission Attended				
33	TU - Transmission Unattended				
34					
35	Summary: Capacity:				
36	748 DU 32,118				
37	24 TA 25,065				
38	134 TU 53,942				
39	906 111,125				
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
2611	7					1
1120	4					2
560	2					3
840	3					4
112	4		*PEAKER	1	75	5
13	1					6
840	3					7
84	3		*PEAKER	1	75	8
332	2		*CUSTOMER SUBSTATION			9
99	3		*CUSTOMER SUBSTATION			10
90	3		*CUSTOMER SUBSTATION			11
840	3					12
120	6	1				13
80	4					14
5	1		MOBIL GENERATOR	1	1	15
1119	3					16
84	3					17
3	1	1				18
1120	4					19
56	2					20
2238	6	1				21
56	2					22
56	2					23
280	1					24
144	1					25
133	1					26
14	1	1				27
560	2					28
500	2					29
56	2					30
560	2					31
112	4					32
2115	11					33
1120	4					34
45	2					35
560	2					36
17	6	1				37
28	1					38
560	2					39
28	2					40

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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 Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
14	1					1
840	3					2
100	2		*PHASE SHIFTER	1	56	3
560	2					4
560	2					5
73	3					6
500	2					7
56	2					8
2	3	1				9
840	3					10
1120	4					11
112	2					12
1030	4					13
56	2					14
840	3					15
45	2					16
2238	6	1				17
840	3					18
56	2					19
2	1					20
4692	12	1				21
840	3					22
56	2		*PEAKER	1	75	23
840	3					24
1120	4					25
106	4					26
840	3					27
28	1					28
840	3					29
112	4					30
2238	6	1				31
1120	4	1				32
200	3	1				33
44	2					34
13	1					35
1119	3	1				36
560	2					37
560	2					38
40	2					39
78	3					40

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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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
810	3					1
56	2					2
280	1					3
560	2					4
1060	4					5
56	2					6
157	6					7
1120	4					8
112	4					9
3357	9	1				10
560	2		TEMPORARY BANK	1	280	11
28	1					12
2800	5					13
73	3					14
560	2					15
40	7					16
1120	4					17
162	3					18
112	4					19
560	2					20
56	2					21
780	3					22
90	4					23
4476	12	1				24
504	2					25
1090	4					26
840	3					27
100	4					28
560	2					29
116	2					30
10	1					31
14	1					32
60	1					33
80	4					34
120	1					35
229	2					36
44	1					37
133	1	1				38
1	6					39
84	1					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
21	1					1
65	1		*CUSTOMER SUBSTATION			2
168	3					3
158	2					4
5	3					5
250	1					6
720	2					7
1120	4					8
270	6	1				9
163	1					10
112	4					11
24	2					12
1	1					13
4	1					14
2	1					15
4	3	1				16
38	4					17
50	6	1				18
14	2					19
4	1					20
180	2					21
75	1		*CUSTOMER SUBSTATION			22
14	1		*CUSTOMER SUBSTATION			23
100	1					24
11	8	1				25
7	2					26
2	3	1				27
21	1					28
11	1					29
20	1		*CUSTOMER SUBSTATION			30
14	1					31
4	1					32
3	1					33
14	1		*CUSTOMER SUBSTATION			34
56	2		*CUSTOMER SUBSTATION			35
3117	9	2				36
3996	12	2				37
560	2					38
56	2					39
14	1		*CUSTOMER SUBSTATION			40

SUBSTATIONS (Continued)

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14	1					1
22	1		*CUSTOMER SUBSTATION			2
129	5					3
56	2					4
101	4					5
112	4					6
21	4	1				7
13	2					8
56	2					9
76	3					10
24	6	1				11
14	2					12
2	3	1				13
3	1					14
28	1		*CUSTOMER SUBSTATION			15
10	1		*CUSTOMER SUBSTATION			16
80	4		*CUSTOMER SUBSTATION			17
73	3					18
84	3					19
21	2					20
14	1		*CUSTOMER SUBSTATION			21
22	1		*CUSTOMER SUBSTATION			22
84	3					23
84	3					24
96	4					25
28	2					26
73	3					27
101	4					28
7	1		*CUSTOMER SUBSTATION			29
24	2					30
50	2					31
5	3	1				32
84	3					33
3	3	1				34
27	2					35
8	1					36
50	2					37
112	2					38
112	4					39
84	4					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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56	2					1
8	1					2
5	3	1				3
84	3					4
101	3					5
11	2					6
6	3					7
81	3					8
11	1					9
84	3					10
6	1					11
25	4					12
9	1	1				13
10	1					14
10	1					15
141	6					16
38	3					17
11	1					18
8	1					19
27	2		*CUSTOMER SUBSTATION			20
56	2					21
112	4					22
11	4					23
28	2					24
25	2					25
40	2					26
28	1		*CUSTOMER SUBSTATION			27
84	3					28
28	1		*CUSTOMER SUBSTATION			29
56	2					30
42	2					31
14	2					32
28	1					33
100	4					34
64	3					35
45	2					36
19	1		*CUSTOMER SUBSTATION			37
21	2					38
20	2					39
56	2					40

SUBSTATIONS (Continued)

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44	2					1
5	2					2
45	2					3
56	2					4
101	4					5
1	3					6
78	3					7
12	6					8
84	3					9
14	2					10
14	1		*CUSTOMER SUBSTATION			11
19	2					12
104	6					13
5	3	1				14
73	3					15
45	2		*CUSTOMER SUBSTATION			16
42	3					17
28	2					18
112	4					19
73	3					20
45	2					21
56	2					22
4	3	1				23
53	3					24
14	1					25
28	2					26
6	3		*CUSTOMER SUBSTATION			27
11	1		*CUSTOMER SUBSTATION			28
56	2		*CUSTOMER SUBSTATION			29
6	1		*CUSTOMER SUBSTATION			30
101	4					31
112	2					32
84	3					33
42	2					34
101	4					35
48	2					36
66	3					37
56	2					38
14	2					39
6	3	1				40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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11	1		*CUSTOMER SUBSTATION			1
56	2					2
67	2		*CUSTOMER SUBSTATION			3
22	1		*CUSTOMER SUBSTATION			4
112	4					5
12	3	1				6
37	5					7
45	2					8
101	4					9
168	4		*CUSTOMER SUBSTATION			10
104	4					11
95	4					12
28	1		*CUSTOMER SUBSTATION			13
20	2					14
56	4					15
84	3					16
84	3					17
9	3	1				18
14	1		*CUSTOMER SUBSTATION			19
56	2	1				20
30	6		*CUSTOMER SUBSTATION			21
28	1					22
112	4		*CUSTOMER SUBSTATION			23
13	2					24
56	2					25
1	3	1				26
5	1		*CUSTOMER SUBSTATION			27
56	2					28
112	2					29
134	5					30
3	2					31
8	1		*CUSTOMER SUBSTATION			32
101	4					33
14	1					34
28	1		*CUSTOMER SUBSTATION			35
13	2					36
15	2					37
56	2					38
28	2					39
56	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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25	2		*CUSTOMER SUBSTATION			1
92	6					2
118	5					3
96	4					4
25	7					5
70	3					6
21	4	1				7
28	1	4				8
22	1		*CUSTOMER SUBSTATION			9
17	1					10
73	3					11
22	1		*CUSTOMER SUBSTATION			12
1	3	1				13
7	1					14
56	2					15
14	1		*CUSTOMER SUBSTATION			16
6	3	1				17
101	4					18
7	1					19
7	1					20
45	2		*CUSTOMER SUBSTATION			21
104	4					22
56	2					23
84	3					24
6	3	1				25
14	1		*CUSTOMER SUBSTATION			26
10	2					27
45	2					28
10	1		*CUSTOMER SUBSTATION			29
45	2		*CUSTOMER SUBSTATION			30
45	2					31
17	4					32
100	3		*CUSTOMER SUBSTATION			33
69	3					34
14	1		*CUSTOMER SUBSTATION			35
28	2		*CUSTOMER SUBSTATION			36
28	1		*CUSTOMER SUBSTATION			37
15	4					38
14	1		*CUSTOMER SUBSTATION			39
84	3					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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11	1					1
14	1					2
5	3					3
42	2					4
4	3	1				5
56	2					6
10	2					7
50	4					8
112	2					9
45	2					10
28	2					11
11	1					12
84	3					13
112	2					14
56	2					15
106	4					16
73	3					17
45	2					18
112	4					19
6	3	1				20
15	2					21
78	3					22
12	6	1				23
96	4					24
112	4					25
45	2		*CUSTOMER SUBSTATION			26
45	2					27
9	4					28
56	2					29
22	1		*CUSTOMER SUBSTATION			30
50	2					31
101	4					32
14	2					33
56	2					34
1	3	1				35
14	1		*CUSTOMER SUBSTATION			36
22	1					37
93	4					38
28	1	1				39
65	3					40

SUBSTATIONS (Continued)

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21	2					1
56	2					2
9	3	1				3
11	1		*CUSTOMER SUBSTATION			4
94	4					5
9	3	1				6
8	3	1				7
14	1		*CUSTOMER SUBSTATION			8
14	1		*CUSTOMER SUBSTATION			9
53	4	1				10
45	2					11
84	3					12
6	3					13
9	3	1				14
112	2					15
14	1					16
21	2					17
14	1		*CUSTOMER SUBSTATION			18
28	2					19
22	1					20
41	2					21
15	2					22
22	1		*CUSTOMER SUBSTATION			23
90	4					24
100	4					25
78	3					26
6	1					27
4	3	1				28
4	1					29
56	2					30
84	3					31
7	6	1				32
28	2					33
7	1					34
11	2					35
19	1					36
1	1	1				37
45	2					38
6	1		*CUSTOMER SUBSTATION			39
56	2					40

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112	4					1
14	1		*CUSTOMER SUBSTATION			2
4	1					3
101	4					4
42	2					5
14	1	1				6
6	1					7
6	3	1				8
3	1					9
11	1					10
25	2					11
56	2		*CUSTOMER SUBSTATION			12
8	1		*CUSTOMER SUBSTATION			13
25	2					14
56	2					15
56	2					16
28	2					17
101	4					18
56	2		*CUSTOMER SUBSTATION			19
14	2					20
5	1					21
18	2					22
56	3					23
25	2		*CUSTOMER SUBSTATION			24
28	2					25
17	2					26
56	2		*CUSTOMER SUBSTATION			27
14	1		*CUSTOMER SUBSTATION			28
21	2					29
11	2					30
5	1					31
44	2					32
21	2					33
112	4					34
101	4					35
56	2					36
19	6					37
17	1		*CUSTOMER SUBSTATION			38
56	2		*CUSTOMER SUBSTATION			39
112	2					40

SUBSTATIONS (Continued)

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56	2	1				1
2	3	1				2
5	3					3
101	4					4
28	1	1				5
48	2					6
11	1					7
56	2					8
112	4					9
78	3					10
5	1					11
17	6	1				12
9	4	1				13
84	3					14
45	2					15
15	2					16
101	4					17
56	2					18
10	1		*CUSTOMER SUBSTATION			19
78	3					20
98	4					21
73	3					22
56	2					23
25	2					24
78	3					25
90	4					26
6	6	1				27
22	1	1				28
11	1					29
84	3					30
56	2					31
39	4	1				32
56	2					33
6	3					34
73	3					35
7	1					36
84	3					37
28	1		*CUSTOMER SUBSTATION			38
28	1					39
40	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
14	4					1
48	2					2
112	4					3
149	6					4
11	1					5
56	2					6
3	3	1				7
11	1		*CUSTOMER SUBSTATION			8
56	2					9
76	3					10
56	2		*CUSTOMER SUBSTATION			11
20	2					12
14	1					13
3	3	1				14
40	2					15
8	3					16
67	3		*CUSTOMER SUBSTATION			17
56	2					18
15	6					19
28	2					20
6	3	1				21
21	2					22
101	4					23
15	2					24
8	3	1				25
56	2					26
6	3					27
84	3					28
56	2					29
81	4					30
20	1	1				31
20	2					32
56	2					33
90	4					34
106	4					35
11	2					36
28	2					37
62	3					38
15	2					39
14	1					40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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112	4					1
11	2					2
22	1		*CUSTOMER SUBSTATION			3
64	2					4
17	1					5
10	1					6
5	1					7
1	1					8
1	1					9
168	6		*CUSTOMER SUBSTATION			10
38	20		*CUSTOMER SUBSTATION			11
19	19		*CUSTOMER SUBSTATION			12
101	4					13
12	6	1				14
15	6					15
56	3					16
17	2					17
6	3	1				18
7	1		*CUSTOMER SUBSTATION			19
112	4					20
45	2					21
6	3					22
42	2					23
90	4					24
28	2					25
9	2					26
45	2					27
25	2					28
45	2					29
28	2					30
4	6	1				31
7	1					32
12	6					33
101	4					34
90	4					35
56	2					36
25	1		*CUSTOMER SUBSTATION			37
28	1					38
28	1					39
106	2					40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
73	3					1
45	2					2
25	2					3
101	4					4
112	4					5
112	4					6
28	2					7
20	4	1				8
28	1					9
84	3					10
11	1					11
101	4					12
45	2					13
28	2		*CUSTOMER SUBSTATION			14
5	1					15
2	3	1				16
101	4					17
56	2		*CUSTOMER SUBSTATION			18
12	3		*CUSTOMER SUBSTATION			19
14	1		*CUSTOMER SUBSTATION			20
28	2					21
101	4					22
56	3					23
73	3					24
15	2					25
56	2					26
56	2	1				27
66	4					28
14	2					29
28	2					30
11	4					31
84	3					32
11	1		*CUSTOMER SUBSTATION			33
81	4					34
28	1		*CUSTOMER SUBSTATION			35
56	2		*CUSTOMER SUBSTATION			36
28	2					37
3	3	1				38
28	3	1				39
9	1		*CUSTOMER SUBSTATION			40

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	2					1
5	3	1				2
21	2					3
45	2					4
5	3					5
90	4					6
8	3	1				7
22	1		*CUSTOMER SUBSTATION			8
73	3					9
56	2					10
56	3					11
5	2					12
5	6					13
56	1					14
84	3					15
56	2					16
2	3	1				17
76	3					18
3	3	1				19
18	2					20
100	4					21
56	2		*CUSTOMER SUBSTATION			22
25	1					23
50	2					24
87	4					25
28	1		*CUSTOMER SUBSTATION			26
15	2					27
53	2					28
15	2					29
39	2		*CUSTOMER SUBSTATION			30
28	1		*CUSTOMER SUBSTATION			31
14	1					32
56	2					33
73	3					34
14	1		*CUSTOMER SUBSTATION			35
14	1		*CUSTOMER SUBSTATION			36
6	5	1				37
22	1		*CUSTOMER SUBSTATION			38
9	1		*CUSTOMER SUBSTATION			39
12	6					40

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
38	4					1
112	4					2
9	6	2				3
112	4					4
28	1					5
56	2		*CUSTOMER SUBSTATION			6
48	2					7
22	1		*CUSTOMER SUBSTATION			8
56	2					9
34	1		*CUSTOMER SUBSTATION			10
56	2					11
70	2					12
106	4					13
14	1		*CUSTOMER SUBSTATION			14
32	2					15
45	2					16
101	4					17
56	2					18
28	2					19
81	4					20
14	1					21
28	1		*CUSTOMER SUBSTATION			22
22	1		*CUSTOMER SUBSTATION			23
56	2					24
21	2					25
6	3	1				26
21	2					27
28	1		*CUSTOMER SUBSTATION			28
14	1		*CUSTOMER SUBSTATION			29
13	1		*CUSTOMER SUBSTATION			30
13	1		*CUSTOMER SUBSTATION			31
8	1		*CUSTOMER SUBSTATION			32
73	3					33
6	3					34
10	1					35
8	3					36
6	3					37
14	1		*CUSTOMER SUBSTATION			38
6	1					39
22	1		*CUSTOMER SUBSTATION			40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
28	1					1
21	2					2
56	2		*CUSTOMER SUBSTATION			3
56	2					4
84	4					5
14	1		*CUSTOMER SUBSTATION			6
27	3		*CUSTOMER SUBSTATION			7
50	2					8
9	3	1				9
14	1					10
10	3	1				11
19	3		*CUSTOMER SUBSTATION			12
95	4					13
106	4					14
11	1					15
25	3	1				16
11	2					17
101	4					18
101	4					19
95	4					20
56	2					21
25	2					22
50	4					23
11	1	1				24
102	4					25
6	3	1				26
6	3	1				27
22	1		*CUSTOMER SUBSTATION			28
99	6					29
12	6	1				30
96	5	1				31
56	2					32
25	2					33
112	2					34
112	4					35
104	4					36
11	1		*CUSTOMER SUBSTATION			37
50	2					38
112	4					39
56	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
38	6					1
28	1					2
5	3	1				3
90	4					4
6	6					5
45	2		*CUSTOMER SUBSTATION			6
56	2		*CUSTOMER SUBSTATION			7
84	3					8
50	3					9
2	3		*CUSTOMER SUBSTATION			10
112	4		*CUSTOMER SUBSTATION			11
84	3		*CUSTOMER SUBSTATION			12
7	1		*CUSTOMER SUBSTATION			13
28	1		*CUSTOMER SUBSTATION			14
101	4					15
11	1					16
45	2		*CUSTOMER SUBSTATION			17
28	2					18
8	3					19
28	2					20
22	1					21
28	2					22
14	1					23
73	3					24
56	3					25
5	1					26
9	3	1	*CUSTOMER SUBSTATION			27
56	2					28
44	2					29
15	2					30
28	2					31
14	1		*CUSTOMER SUBSTATION			32
14	1		*CUSTOMER SUBSTATION			33
56	2					34
13	2					35
28	1		*CUSTOMER SUBSTATION			36
40	2		*CUSTOMER SUBSTATION			37
8	1		*CUSTOMER SUBSTATION			38
88	4					39
112	4					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
56	2		*CUSTOMER SUBSTATION			1
56	2					2
14	1		*CUSTOMER SUBSTATION			3
101	4					4
56	2		*CUSTOMER SUBSTATION			5
68	3					6
28	2					7
37	4					8
58	4					9
6	3					10
56	2					11
11	2					12
28	2		*CUSTOMER SUBSTATION			13
68	3					14
21	2					15
10	1					16
10	1					17
56	3					18
112	4					19
28	2					20
45	2					21
112	4					22
11	1					23
56	2					24
56	2					25
56	2					26
7	1					27
56	2					28
112	4					29
14	1					30
28	1		*CUSTOMER SUBSTATION			31
6	1		*CUSTOMER SUBSTATION			32
170	8		*CUSTOMER SUBSTATION			33
6	3					34
22	1		*CUSTOMER SUBSTATION			35
56	2					36
14	1					37
101	4					38
10	2					39
56	3					40

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	3	1				1
25	2					2
101	4					3
11	1		*CUSTOMER SUBSTATION			4
112	2					5
56	2					6
14	1		*CUSTOMER SUBSTATION			7
101	4					8
56	2					9
6	3	1				10
76	3					11
112	4					12
11	1	1				13
7	1					14
17	1		*CUSTOMER SUBSTATION			15
28	2		*CUSTOMER SUBSTATION			16
70	3					17
13	2					18
106	4					19
112	4					20
50	2					21
45	2					22
56	2					23
56	2					24
5	1					25
75	4					26
25	2					27
5	3	1				28
56	2					29
56	2					30
56	2					31
3	1					32
56	3					33
9	1					34
45	2					35
14	1		*CUSTOMER SUBSTATION			36
56	2					37
56	2					38
28	1	1				39
14	1		*CUSTOMER SUBSTATION			40

Name of Respondent Southern California Edison Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2019	Year/Period of Report End of 2018/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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 Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	3	1				1
14	1					2
13	1		*CUSTOMER SUBSTATION			3
28	2		*CUSTOMER SUBSTATION			4
45	2		*CUSTOMER SUBSTATION			5
14	1		*CUSTOMER SUBSTATION			6
28	1		*CUSTOMER SUBSTATION			7
28	1					8
28	1	1				9
1	1					10
14	1		*CUSTOMER SUBSTATION			11
14	1					12
72	3					13
28	2					14
21	2					15
21	2					16
56	2					17
28	2					18
4	3	1				19
5	1					20
84	3					21
101	4					22
56	2					23
84	3					24
28	2					25
28	2					26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Other Accounts Receivable	Edison International	143	4,281,262
3	Accounts Receivable from Associated Companies	Edison International	146	174,307
4	PrePayments	Edison International	165	157,031,082
5	Accumulated Provision for Pensions and Benefits	Edison International	228.3	770,829
6	Accounts Payable	Edison International	232	1,347,491
7	Tax Accrued	Edison International	236	-57,662,259
8	Miscellaneous Current and Accrued Liabilities	Edison International	242	688,780
9	Other Deferred Credits	Edison International	253	1,369,555
10	Other Utility Operating Income	Edison International	414	12,500
11	Donations	Edison International	426.1	19,990,310
12	Expenditures for Certain Civic, Pol. & Rel. Activ.	Edison International	426.4	8,458,941
13	Other Deductions	Edison International	426.5	571,153
14	Other Interest Exense	Edison International	431	618,437
15	Dividends Declared	Edison International	438	576,000,000
16	Adjustment to Retained Earnings	Edison International	439	1,815,550
17	Admin. & Gen. Salaries/Office Supp. & Exp.	Edison International	920	168,884
18	Outside Services Employed	Edison International	923	17,021,939
19	Property Insurance	Edison International	924	-911,095
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison International	131	-7,415,047
22	Prepayments	Edison International	165	37,443
23	Accounts Payable	Edison International	232	4,024,570
24	Miscellaneous Current and Accrued Liabilities	Edison International	242	169,607
25	Taxes Other Than Inc. Taxes, Utility Op. Income	Edison International	408.1	80,940
26	Other Deductions	Edison International	426.5	59,934
27	Rent	Edison International	454	1,936,253
28	Other Electric Revenues	Edison International	456	74,592
29	Miscellaneous Distribution Expenses	Edison International	588	38,166
30	Demonstrating and Selling Expenses	Edison International	912	390
31	Admin. & Gen. Salaries/Office Supp. & Exp.	Edison International	920	1,280,007
32	Outside Services Employed	Edison International	923	108,932
33	Injuries and Damages	Edison International	925	11,583
34	Employee Pension and Benefits	Edison International	926	3,727,184
35	Miscellaneous General Expenses	Edison International	930.2	7,037
36				
37			TOTAL	4,141,591
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Injuries and Damages	Edison International	925	177,532

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Miscellaneous General Expenses	Edison International	930.2	4,597,204
4	Rent	Edison International	931	37,286
5				
6			TOTAL	736,559,688
7				
8				
9				
10	Prepayments	Edison Insurance Services	165	22,422,547
11	Injuries and Damages	Edison Insurance Services	925	-1,000,000,000
12				
13			TOTAL	-977,577,453
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison Mission Group	131	121,131
22	Accounts Payable	Edison Mission Group	232	160,000
23	Miscellaneous Current and Accrued Liabilities	Edison Mission Group	242	1,083
24	Taxes Other Than Inc. Taxes, Utility Op. Income	Edison Mission Group	408.1	9,526
25	Other Deductions	Edison Mission Group	426.5	1
26	Rent	Edison Mission Group	454	62,865
27	Other Electric Revenues	Edison Mission Group	456	9,029
28	Admin. & Gen Salaries/Office Supp. & Exp.	Edison Mission Group	920	176,864
29	Injuries and Damages	Edison Mission Group	925	1,368
30	Employee Pension and Benefits	Edison Mission Group	926	67,096
31	Miscellaneous General Expenses	Edison Mission Group	930.2	270
32				
33			TOTAL	609,233
34				
35				
36				
37				
38				
39				
40				
41				
42				
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.
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3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Cash	Edison Energy Group	131	72,581
22	Accounts Payable	Edison Energy Group	232	101,674
23	Miscellaneous Current and Accrued Liabilities	Edison Energy Group	242	46,618
24	Taxes Other Than Inc. Taxes, Utility Op. Income	Edison Energy Group	408.1	40,343
25	Other Deductions	Edison Energy Group	426.5	100
26	Rent	Edison Energy Group	454	265,855
27	Other Electric Revenues	Edison Energy Group	456	36,308
28	Other Expenses	Edison Energy Group	557	375
29	Admin. & Gen. Salaries/Office Supp. & Exp.	Edison Energy Group	920	715,528
30	Outside Services Employed	Edison Energy Group	923	193
31	Injuries and Damages	Edison Energy Group	925	5,774
32	Employee Pension and Benefits	Edison Energy Group	926	427,958
33	Miscellaneous General Expenses	Edison Energy Group	930.2	15,577
34				
35			TOTAL	1,728,884
36				
37				
38				
39				
40				
41				
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Southern California Edison Company	(1) [X] An Original (2) [ ] A Resubmission	04/17/2019	End of 2018/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
7				
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10				
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17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
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32				
33				
34				
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37				
38				
39				
40				
41				
42				

Schedule Page: 429 Line No.: 2 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 3 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 4 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 5 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 6 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 7 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 8 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 9 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 10 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 11 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 12 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 13 Column: a

(B) 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.: 14 Column: a

(B) 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.: 15 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 16 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 17 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(D) 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.: 18 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 19 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 21 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 22 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 23 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 24 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 25 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 26 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 27 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 28 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 29 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 30 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429 Line No.: 31 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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.: 32 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(D) 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: a

(B) 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.: 2 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.: 3 Column: a

(B) 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.: 4 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 10 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 11 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

For the years ended December 31, 2018 and 2017, SCE purchased wildfire liability insurance from Edison Insurance Services, Inc. ("EIS"), a wholly-owned subsidiary of Edison International. EIS fully reinsured the exposure for these policies through the commercial reinsurance market, with reinsurance limits and premiums equal to those of the insurance purchased by SCE. The $1 billion in expected recoveries from these insurance policies was recorded in FERC account 228.2 Accumulated Provision for Injuries and Damages. EIS does not earn a margin on these commercial reinsurance policies. The off-setting credits were recorded to FERC account 925 Injuries and damages.

Schedule Page: 429.1 Line No.: 21 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 22 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 23 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 24 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 25 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 26 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 27 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.1 Line No.: 28 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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.: 30 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(D) 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.: 31 Column: a

(B) 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.: 21 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 22 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 23 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 24 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 25 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 26 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 27 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 28 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

Schedule Page: 429.2 Line No.: 29 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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.: 31 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(B) 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.

(D) 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.: 32 Column: a

(A) Directly Charged: All costs associated with services are billed to/from the utility.

(D) 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.: 33 Column: a

(B) 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.

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<u>Schedule</u> <u>Page No.</u>