SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company **Docket No. ER18-______-000**

SOUTHERN CALIFORNIA EDISON COMPANY

TRANSMISSION OWNER TARIFF
TRANSMISSION RATE FILING
(TO2018)

VOLUME 2

PREPARED DIRECT TESTIMONY AND EXHIBITS

(EXHIBITS SCE-1 THRU SCE-21)

OCTOBER 2017

SOUTHERN CALIFORNIA EDISON

An EDISON INTERNATIONAL® Company

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Prepared Direct Testimony and Supporting Exhibits (SCE-1 thru SCE-21)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
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PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-1)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
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SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON

(EXHIBIT SCE-1)

Mr. Nelson provides an overview of SCE's filing in this docket, including: 1) background on SCE's transmission system and its Base Transmission Revenue Requirement ("Base TRR"), and to explain why SCE is filing a new formula rate at this time, 2) an overview of the design and operation of SCE's Formula Rate proposal, 3) an introduction to some of the revisions to the proposed Formula Rate that SCE compared to the currently-effective Formula Rate ("Original Formula Rate"), 4) SCE's requested implementation date for the Formula Rate, 5) an overview of SCE's requested Return on Equity ("ROE"), 6) a description of SCE's proposed Base TRR amount for January 1, 2018 based on the proposed Formula Rate, and 7) an introduction of SCE's witnesses and the purpose of their testimony.

UNITED STATES OF AMERICA
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PREPARED DIRECT TESTIMONY OF
JEFFREY L. NELSON
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Jeffrey L. Nelson, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Please briefly describe your present responsibilities at Southern California Edison (“SCE” or “Edison”).

A. I am the Director of FERC Rates and Market Integration at Southern California Edison Company (“SCE”). My duties include managing engagement and filings with the Federal Energy Regulatory Commission (“FERC” or “Commission”) concerning California ISO market related issues, and with the preparation of revenue requirement, rate, tariff, and contract filings. This includes annual filings in support of SCE’s current Formula Transmission Rate, as well as the development of the proposed Formula Rate contained in this filing.

Q. Please briefly describe your educational and professional background.

A. I have over 25 years of experience in the electric utility industry. I’ve held positions as an electrical engineer, analyst, energy trader, and performed regulatory strategy and engagement as both a project manager and a manager. I hold a Bachelor's degree in electrical engineering from the University of California, Los Angeles, as well as an MBA from the Anderson school at UCLA. Also, I was awarded a Charted Financial Analyst charter (CFA charter) in 2003 but am currently not in active standing.

Q. Have you submitted testimony or affidavits to the Commission previously?

A. Yes. I have submitted affidavits in Dockets PA02-2, EL03-157, EL09-62 and ER13-1060.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1) Provide background on SCE's transmission system and its Base Transmission Revenue Requirement ("Base TRR"), and explain why SCE is filing a new Formula Rate at this time;

2) Provide an overview of the design and operation of SCE's Formula Rate proposal;

3) Describe at a high level some of the revisions to the Formula Rate that SCE is proposing in this filing as compared to the currently-effective Formula Rate ("Original Formula Rate");

4) Discuss SCE's requested implementation date for the Formula Rate;

5) Provide an overview of SCE's requested Return on Equity ("ROE");

6) Present SCE's proposed Base TRR amount for January 1, 2018 based on the proposed Formula Rate; and,

7) Introduce SCE's witnesses and the purpose of their testimony.

II. BACKGROUND ON SCE'S BASE TRR

Q. Please define SCE's Base TRR.

A. SCE's Base TRR represents the costs of owning and operating the transmission facilities and entitlements that SCE has placed under the California Independent System Operator's ("CAISO") Operational Control. In the case where the Commission has approved recovery of Construction Work In Progress ("CWIP") in transmission rate base for certain transmission projects that will be placed under the CAISO's Operational Control, the Base TRR also includes capital costs associated with these projects in advance of their being completed and placed under the Operational Control of the CAISO. The Base TRR excludes the Transmission Revenue Balancing Account Adjustment (TRBAA) and, for wholesale purposes, also excludes Standby Transmission Revenues.

Q. Please provide background on SCE's determination of its Base TRR.

A. SCE first established a Base TRR in April of 1998, corresponding to the date upon which the CAISO assumed Operational Control of SCE's network transmission facilities. SCE's first five rate cases, covering service from 1998 through the end of 2011, were "stated rate" rate cases in which the Base TRR and associated retail and wholesale rates were determined as stated amounts, and remained in effect until the next rate case was accepted by the Commission. During the period from March, 2008 through the end of 2011 SCE also had a separate rate mechanism to recover the TRR associated with CWIP projects (established in Docket No. ER08-375), so that during that time SCE's total Base TRR was the sum of the stated rate case Base TRR and the CWIP TRR.

In 2011 SCE filed the Original Formula Rate in Docket No. ER11-3697. Since the Original Formula Rate includes recovery of CWIP costs through a component of Rate Base, the separate CWIP rate mechanism was no longer required and was terminated. The Commission accepted the Original Formula Rate effective January 1, 2012, and set the case for settlement. SCE filed a settlement offer on August 26, 2013, which the Commission approved in a letter order issued November 5, 2013.[1]

Q. Please explain how the Base TRR has been established since the Original Formula Rate became effective.

A. SCE's Formula Rate, like most formulas, provides for Annual Updates to determine the Base TRR and associated retail and wholesale transmission rates for a period of one year. Initially, SCE's proposed Original Formula Rate set the Base TRR for a one-year period from October 1 through September 30. The settlement of the Original Formula Rate established the timelines that SCE has been operating under since 2013, which provide for Annual updates to be filed by each December 1, with the Base TRR to be effective for the following calendar year.

SCE has filed five Annual Updates since the filing of the Original Formula Rate (SCE refers to these Annual Updates as TO7 through TO11). The TO11 Filing established the current Base TRR of $1.189 billion. Contemporaneously with this proposed Formula Rate filing, SCE is filing the TO12 Annual Update under the Original Formula Rate. The Original Formula Rate TO12 filing determines the actual cost of service for the 2016 year (the 2016 "True Up TRR"), and additionally will determine SCE's Base TRR and associated retail and wholesale rates in the event that the Commission does not accept the proposed Formula Rate with an effective date of January 1, 2018.

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[1] *Southern California Edison Company* 145 FERC 61,103 (2013).

Q. Why is SCE filing a Formula Rate at this time?

A. Section 2.5 of the settlement of SCE's Original Formula Rate specifies that the Original Formula Rate shall terminate on December 31, 2017:

> Except as provided in the Formula Rate Protocols, the Formula Rate shall terminate on December 31, 2017 (the "Formula Rate Termination Date").

Additionally, the protocols for the Original Formula Rate specify that SCE must file a replacement Base TRR mechanism no later than 60 days before the Formula Rate Termination Date:

> Except as set forth below, the Formula Rate shall terminate December 31, 2017. SCE shall submit a filing under Section 205 of the Federal Power Act by no later than 60 days prior to December 31, 2017, proposing a transmission rate schedule, which may include revised transmission rates. The rates and other components of such filing shall be at SCE's sole discretion, and may be in the form of a formula rate or a traditional stated rate. Parties retain all rights to oppose the filing. Such filing shall request an effective date of January 1, 2018. In the event that the Commission does not permit the proposed rate schedule and the associated rates to become effective on January 1, 2018, this Formula Rate shall remain in effect until the date that the rate filing is made effective by the Commission. (Original Formula Rate Protocols, Section 2)

Thus, pursuant to the settlement and protocols of the Original Formula Rate, SCE must make a filing to establish a new Base TRR rate by October 31, 2017, seeking an effective date of January 1, 2018. SCE has chosen to file another formula rate rather than a stated rate at this time for the proposed January 1, 2018 Base TRR determination.

Q. Why has SCE determined to continue with a formula rate?

A. In moving to a formula rate in 2012, SCE considered the relative benefits of a formula rate compared to a stated rate and determined that a formula rate was preferable at that time due to: 1) SCE's extensive transmission program was resulting in corresponding increases to SCE's Base TRR that SCE could not fully recover given the Commissions suspension policy; 2) SCE determined that a formula rate is likely to reduce litigation costs relative to annual stated rate filings, particularly since forecasts of Rate Base additions are less important due to the True Up provision of SCE's Formula Rate; and 3) the Commission had indicated that it supported formula rates for transmission owners. These considerations all remain at this point in time. Additionally, with almost six years of experience operating under a formula rate, SCE believes that the advantages listed above have been realized and remain likely to be realized over the next several years. Of note, during the life of the Original Formula Rate, no protests were filed against SCE. And in general, the process has led to constructive interaction prior to filing annual updates. Accordingly, SCE has chosen to file another Formula Rate at this time.

Q. What is SCE's proposed effective date for this new Formula Rate?

A. SCE's proposed effective date for this new Formula Rate is January 1, 2018, in accordance with Section 2 of the Protocols of the Original Formula Rate.

III. OVERVIEW OF SCE'S PROPOSED FORMULA RATE

Q. Please provide a description of SCE's proposed Formula Rate.

A. SCE's proposed Formula Rate consists of two components: 1) The Formula Rate Protocols (Attachment 1 to Appendix IX of SCE's Transmission Owner Tariff); and 2) The Formula Rate Spreadsheet (Attachment 2 to Appendix IX of SCE's Transmission Owner Tariff). The Formula Rate Protocols set forth the process-related aspects of the Formula Rate, including the timelines for submission of an Annual Update, as well as set forth some requirements that SCE must adhere to. The Formula Rate Spreadsheet sets forth the calculations that are to be followed in determining the Base TRR and associated retail and wholesale rates in each Annual Update. Mr. Hansen describes in detail the structure of the Formula Rate Protocols and Spreadsheet in his testimony, Exhibit SCE-3.

Q. What is the basic structure of the determination of the Base TRR in the proposed Formula Rate?

A. SCE's Base TRR is defined as the sum of three components: 1) the Prior Year TRR; 2) the Incremental Forecast Period TRR; and 3) the True Up Adjustment. Under certain conditions as defined in the protocols, SCE will also include a "Cost Adjustment", which would be a fourth component. Additionally, the Formula Rate calculates a "True Up TRR" that represents SCE's actual costs of owning and operating its ISO-controlled transmission assets in the year previous to the Annual Update (the "Prior Year"). The workings of each element of the Base TRR are discussed in depth by Mr. Hansen in Exhibit SCE-3.

Q. What is the Prior Year TRR?

A. The Prior Year TRR represents SCE's costs of owning and operating its ISO-controlled transmission system, measured at the end of the Prior Year. Mr. Hansen explains in detail the determination of the Prior Year TRR in his testimony, Exhibit SCE-3.

Q. What is the Incremental Forecast Period TRR?

A. The Incremental Forecast Period TRR represents the additional TRR costs that SCE expects to incur during the Rate Year (the forthcoming year for which the Base TRR determined in an Annual Update will be in effect), incremental to the costs already reflected in the Prior Year TRR. By definition, the sum of the Prior Year TRR and the Incremental Forecast Period TRR represent the expected Base TRR costs that SCE will incur during the Rate Year. Mr. Hansen explains in detail the determination of the Incremental Forecast Period TRR in his testimony, Exhibit SCE-3.

Q. What is the True Up TRR?

A. As stated above, the True Up TRR represents SCE's actual Base TRR costs experienced in the historic Prior Year. The Rate Base component of the Base TRR is calculated on an average basis over the Prior Year (as compared to the Prior Year TRR which utilized an End-of-Year Rate Base). Mr. Hansen explains in detail the determination of the True Up TRR in his testimony, Exhibit No. SCE-3.

Q. What is the True Up Adjustment?

A. The True Up Adjustment component of the Base TRR ensures that over time SCE recovers its actual costs of owning and operating its CAISO-controlled transmission assets, as defined by the True Up TRR. The True Up Adjustment is determined by comparing SCE's actual retail transmission revenues attributable to the Formula Rate to SCE's True Up TRR. The difference between the two, whether an undercollection or an overcollection, is the basis of the True Up Adjustment component of the Base TRR. Mr. Hansen explains in detail the determination of the True Up Adjustment in his testimony, Exhibit No. SCE-3.

Q. Is SCE proposing any revisions to the Formula Rate as compared to the Original Formula Rate?

A. Yes. While the general structure of the Formula Rate is the same, SCE is proposing some revisions to the Formula Rate, including the Formula Rate Protocols and the Formula Rate Spreadsheet.

Q. Why is SCE proposing revisions to the Formula Rate?

A. The revisions that SCE is proposing to the Formula Rate are for three general reasons:

1) To improve the operation of the Formula Rate, including simplification of calculations in some instances;

2) To reflect current conditions with respect to certain stated values in the Formula Rate (e.g. Return on Equity and Depreciation Rates); and
3) To reflect what SCE believes is Commission policy with respect to the recovery of certain costs.

Q. Please describe some of the significant revisions that SCE is proposing to make to the Formula Rate as compared to the Original Formula Rate.

A. Some significant proposed revisions to the Formula Rate that SCE is proposing are:

1) A new stated value for ROE (supported by Dr. Paul Hunt in Exhibit SCE-17).
2) Updated stated depreciation rates (supported by Mr. David Gunn in Exhibit SCE-7).
3) A simplification of the calculation of Operations and Maintenance Expense ("O&M Expense"), so that the calculation of the ISO O&M expense recovered in the Formula will continue to align with cost causation but rely on fewer allocation factors and be more transparent (supported by Mr. Jacob Moon in Exhibit No. SCE-9 and Mr. Allstun in Exhibit SCE-10).
4) A simplification of the determination of the intra-year balances of ISO Transmission Plant and ISO Accumulated Depreciation (supported by Mr. Gunn in Exhibit No. SCE-7).
5) A simplification of the mechanism to determine the amount of Post Retirement Benefits Other than Pensions Expense ("PBOPs Expense") to be recovered (supported by Mr. Hansen in Exhibit SCE-3).
6) A simplification and revision of the True Up Adjustment component of the Base TRR, which should yield an easier to understand mechanism that will continue to accurately track SCE's cumulative over or

underrecovery of Base TRR costs, as well as ensure a more timely treatment of the True Up Adjustments in Annual Updates, either in the positive or negative direction (as supported by Mr. Hansen in Exhibit SCE-3).

7) Revisions to recover certain incentive compensation costs that are not recovered in the Original Formula Rate but are eligible for recovery under Commission policy (supported by Mr. Mindess in Exhibit SCE-12).

8) Modification of the method of calculation of the Cash Working Capital component of Rate Base to be based on 1/8 of O&M and A&G expenses (as supported by Mr. Gunn in Exhibit SCE-7).

There are, of course, many additional less significant revisions that SCE is proposing to make to the Formula Rate. Exhibit SCE-5, supported by Mr. Hansen, presents a listing of all proposed revisions to the Formula Rate Spreadsheet, and the witness supporting each. Exhibit SCE-6, also supported by Mr. Hansen, presents a listing of all proposed revisions to the Formula Rate Protocols.

Q. Why is SCE proposing certain revisions to simplify the operation of the Formula Rate?

A. After five years of execution, SCE has found that the Original Formula Rate is somewhat unnecessarily complicated in certain aspects, including specifically the calculation of ISO O&M expense, the True Up Adjustment mechanism, the cost recovery mechanism for SCE's PBOPs Expenses, and the determination of the intra-year balances of ISO Transmission Plant and Accumulated Depreciation. The revisions that SCE is proposing will still yield a reasonable and accurate determination of SCE's Base TRR, while reducing the administrative effort involved in preparing Annual Updates and also providing greater transparency and an easier-to-understand Formula Rate. These are worthy goals and should result in a better Annual Update process both for SCE in preparing the Annual Update, and for SCE's transmission customers when they review SCE's Annual Updates.

Q. Is SCE proposing any other revisions to its TO Tariff other than to the Formula Rate (Appendix IX)?

A. Yes. As described by Mr. Hansen in his testimony (Exhibit SCE-3), SCE is proposing to revise Appendix II to remove certain wholesale transmission rates no longer in use, or to clarify the application of the remaining wholesale rates.

IV. SCE's PROPOSED RETURN ON EQUITY

Q. What is SCE's Proposed Return on Equity ("ROE") for this proposed Formula Rate?

A. SCE's proposed Base ROE is 10.3%. Additionally, pursuant to Commission policy, SCE proposes a 50 basis point ROE adder to reflect SCE participation in a Commission-approved Independent System Operator, the California Independent System Operator. The sum of SCE's proposed Base ROE and the 50 basis point CAISO participation adder, 10.8%, is a stated value on Line 50 of Schedule 1 of the Formula Rate Spreadsheet, and is used to calculate SCE's overall Cost of Capital Rate which is applied to SCE's Rate Base to determine the total Cost of Capital. Dr. Hunt fully supports SCE's requested Base ROE and the inclusion of the 50 basis point ROE adder in his testimony, Exhibit SCE-17.

Q. Has SCE received Commission-approved ROE adders for specific transmission projects?

A. Yes. SCE has received Commission-approved ROE Adders for three transmission projects: 1) The Tehachapi Renewable Transmission Project

("TRTP"), in the amount of 1.25%; 2) Devers to Colorado River ("DCR") project, in the amount of 1.00%; and 3) the Rancho Vista substation project, in the amount of 0.75%. Dr. Hunt fully supports SCE's continued recovery of these Commission-approved project-specific ROE adders in his testimony, Exhibit SCE-17, and Mr. Hansen describes the calculation of the dollar amount of the project specific adders in his testimony, Exhibit SCE-3.

V. SCE'S PROPOSED JANUARY 1, 2018 BASE TRR

Q. Has SCE included a populated version of the proposed Formula Rate Spreadsheet with this filing to determine a proposed January 1, 2018 Base TRR and associated retail and wholesale transmission rates?

A. Yes. Exhibit SCE-4, supported by Mr. Hansen, is SCE's proposed Formula Rate Spreadsheet fully populated with the required cost inputs to determine a Base TRR for 2018. SCE is proposing that the Base TRR and associated rates from the proposed Formula Rate Spreadsheet become effective January 1, 2018, concurrently with the effective date that SCE is requesting for this proposed Formula Rate.

Q. What is SCE'S proposed Base TRR and associated retail and wholesale transmission rates effective January 1, 2018?

A. Under the proposed rates, SCE's proposed Base TRR for calendar year 2018 (effective January 1, 2018) will be $1,169,306,623 (Schedule 1, Line 86 of Exhibit SCE-4). This compares to the current Base TRR of $1,188,757,628, which includes a positive $94.2 million True Up Adjustment related to prior years, filed by SCE in its 2016 TO11 Annual Update and in effect for calendar year 2017. Thus, even though SCE is proposing revisions to the Formula Rate that will increase SCE's actual costs, as defined by the True Up TRR, SCE's proposed 2018 Base TRR is actually lower than its 2017 Base TRR. In part, this decrease in Base TRR from 2017 to 2018 is related to the operation of the

Formula Rate True Up Adjustment mechanism. In particular, SCE is proposing changes to the True Up Adjustment mechanism that will prevent what would otherwise be a positive $59.6 million True Up Adjustment (i.e., additional charge) in 2018 that is not necessary to ensure that SCE recovers its cumulative undercollection (under the existing Formula Rate True Up Adjustment mechanism, this additional charge would ultimately be credited to customers as part of the calculation of a later True Up Adjustment, but in this instance the positive adjustment is not necessary). Instead, SCE's proposed True Up Adjustment for 2018 is negative $39.6 million. Mr. Hansen explains the revised True Up Adjustment mechanism in Exhibit SCE-3. SCE's proposed retail and wholesale transmission rates, calculated pursuant to Schedules 33 and 30 of the Formula Rate Spreadsheet are presented in Exhibit SCE-4.

Q. In the event that the Commission does not accept SCE's proposed Formula Rate and its associated Base TRR on January 1, 2018 as SCE is requesting, how will SCE's Base TRR for January 1, 2018 be determined?

A. Section 2 of the Original Formula Rate protocols provides that in the event that the Commission does not accept SCE's proposed Formula Rate on SCE's requested effective date of January 1, 2018, the Original Formula Rate remains in effect. SCE is submitting contemporaneously (in a different docket) with this filing the TO12 Annual Update. That Annual Update includes a full calculation of a Base TRR for 2018 to be used in the event that the Commission does not accept SCE's proposed new Formula Rate with an effective date of January 1, 2018.

VI. OVERVIEW OF SCE'S WITNESSES AND TESTIMONY

Q. Please present the witnesses that will be providing testimony to support SCE's proposed Formula Rate, and briefly describe what aspects of the proposed Formula Rate their testimony will support.

A. The witnesses in this filing and a brief description of the aspects of the proposed Formula Rate they are supporting are:

1) Mr. Jeffrey L. Nelson (Exhibit SCE-1)

I am providing an overview of SCE's filing.

2) Mr. Berton J. Hansen (Exhibit SCE-3)

Mr. Hansen supports the mechanics of the Formula Rate, including the calculation of the Base TRR pursuant to the Formula Rate Spreadsheet, and the requirements set forth in the Formula Rate Protocols.

3) Dr. Paul T. Hunt (Exhibit SCE-17)

Dr. Hunt supports SCE's proposed Return on Equity and related capital issues.

4) Mr. David Gunn (Exhibit SCE-7)

Mr. Gunn supports SCE's proposed depreciation rates and depreciation expense, and several components of SCE's Rate Base, including ISO Plant in Service and Accumulated Depreciation.

5) Mr. Jacob Moon (Exhibit SCE-9)

Mr. Moon supports the calculation of O&M Expenses, the determination of the jurisdictional split of Transmission assets between Commission and the California Public Utilities Commission by the Plant Study, and the forecast of additions to Transmission Plant in Service and CWIP projects for use in determining the Incremental Forecast Period TRR.

6) Mr. Daniel Allstun (Exhibit SCE-10)

Mr. Allstun supports the application of certain allocation factors to O&M expense accounts in order to determine the FERC jurisdictional portion of O&M expenses.

7) Mr. Alfred Lopez (Exhibit SCE-11)

Mr. Lopez supports several tax-related components of the Base TRR, including: 1) Income Tax Expense; 2) Other Taxes; 3) Accumulated Deferred Income Taxes (“ADIT”); and 4) Some components of the calculation of the Wholesale Difference to the Base TRR.

8) Mr. Antonio Ocegueda (Exhibit SCE-15)

Mr. Ocegueda supports the calculation of the labor and plant allocation factors, as well as certain components of Rate Base and associated expenses: Network Upgrade Credits, Abandoned Plant, Plant Held for Future Use, and Regulatory Assets and Debits.

9) Ms. Jee Kim (Exhibit SCE-13)

Ms. Kim supports the determination of the Revenue Credit component of the Base TRR.

10) Mr. Robert Mindess (Exhibit SCE-12)

Mr. Mindess supports the determination of the Administrative and General (“A&G”) expense component of the Base TRR, and the Franchise Fee and Uncollectibles expense components of the Base TRR.

11) Mr. Robert Thomas (Exhibit SCE-16)

Mr. Thomas supports the calculation of SCE’s retail transmission rates.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Jeffrey L. Nelson, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Jeffrey L. Nelson

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Jeffrey L. Nelson, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

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<u>EXHIBIT SCE-2</u>

EXHIBIT TO THE TESTIMONY OF MR. JEFFREY L. NELSON

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

EXHIBIT SCE-2

Responsible Witnesses for Each Schedule of the Formula Rate Spreadsheet and the Formula Rate Protocols

Schedule	**Witness(es)**	**Exhibit SCE-___**
1-Base TRR	Hansen: Lines 1-6, 8-18, 66-89 Gunn: Cash Working Capital (Line 7) Hunt: Return and Capitalization (Lines 37-56) Lopez: Other Taxes and Income Taxes (Lines 19-36 and 57-65)	3 7 17 11
2-IFPTRR	Hansen	3
3-TU Adjust	Hansen	3
4-TUTRR	Hansen	3
5-ROR (1,2,3,4)	Hunt	17
6-Plant in Service	Gunn	7
7-Plant Study	Moon	9
8-AccDep	Gunn	7
9-ADIT	Lopez	11
10-CWIP	Gunn	7
11-PHFU	Ocegueda	15
12-Aband Plant	Ocegueda	15
13-Work Cap	Gunn	7
14-Incentive Plant	Hansen: Summary Amounts of Incentive Plant (Lines 1-38) and Summary of Incentive Projects and Incentives Granted (Lines 183-221) Gunn: Inputs for Prior Year Net Plant In Service for each Incentive project (Lines 39-182)	3 7
15-Incentive Adders	Hansen	3
16-Plant Additions	Gunn	7
17-Depreciation	Gunn	7
18-Dep Rates	Gunn	7
19-O&M	Moon: Entire Schedule except for Lines 48-87, column 5 Allstun: Allocation factors for each O&M account (Lines 48-87, column 5 “Percent ISO” percentages)	9 10
20-A&G	Mindess	12
21-Revenue Credits	Kim	13
22-NUCs	Ocegueda	15
23-Reg Assets	Ocegueda	15
24-CWIP TRR	Hansen	3

25-Wholesale Difference	Hansen: Lines 1-31 and 36-45 Gunn: Wholesale Depreciation Difference (Line 32) Lopez: Three components of wholesale Difference: Taxes Deferred - Make Up Adjustment (Line 33) Excess Deferred Taxes (Line 34) Taxes Deferred - Acct. 282 ACRS/MACRS (Line 35)	3 7 11
26-Tax Rates	Lopez	11
27-Allocators	Ocegueda: Labor and Plant Allocation Factors (Lines 1-22) Moon: O&M Allocators (Lines 23-48)	15 9
28-FF&U	Mindess	12
29-Wholesale TRRs	Hansen	3
30-Wholesale Rates	Hansen	3
31-HVLV	Moon	9
32- Gross Load	Hansen	3
33-Retail Rates	Thomas	16
34-Unfunded Reserves	Gunn	7
Protocols	Hansen	3

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(EXHIBIT SCE-3)

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SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
BERTON J. HANSEN

(EXHIBIT SCE-3)

Mr. Hansen provides a detailed description of SCE's proposed Formula Rate, including the Formula Rate Protocols and the Formula Rate Spreadsheet. Mr. Hansen explains several cost components that are included in the Base Transmission Revenue Requirement ("TRR"), and identifies other witnesses that are responsible for other components of the Base TRR. Mr. Hansen supports Exhibit SCE-4, the populated Formula Rate Spreadsheet that develops the proposed Base TRR and associated transmission rates for 2018. Additionally, Mr. Hansen explains several revisions to the Formula Rate Spreadsheet relative to the currently-effective Original Formula Rate Spreadsheet, and supports Exhibit SCE-5 (Formula Spreadsheet Revisions), a listing of all revisions to the Formula Rate Spreadsheet relative to the Original Formula Rate. Mr. Hansen also supports the Formula Rate Protocols, which set forth the process for submitting an Annual Update each year, and other requirements that SCE must adhere to. Mr. Hansen explains several revisions to the Formula Rate Protocols relative to the Original Formula Rate Protocols, and supports Exhibit SCE-6 (Formula Protocol Revisions), a listing of all revisions to the Formula Rate Protocols relative to the Original Formula Rate.

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PREPARED DIRECT TESTIMONY OF
BERTON J. HANSEN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Berton J. Hansen, and my business address is 8631 Rush St., Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Project Manager in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include developing rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in economics from the University of California at Riverside, and a Master of Arts Degree in economics from the University of California at San Diego. I have been employed at SCE since 1984 in various positions, including Regulatory Economics Analyst, Power Systems Planner, Financial Analyst, and Project Manager.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in four of SCE's transmission stated rate case proceedings (Docket Nos. ER02-925, ER06-186, ER08-1343, and

ER09-1534), SCE's first formula rate case (Docket No. ER11-3697), the California Independent System Operator's ("CAISO" or "ISO") Transmission Access Charge proceeding (Docket No. ER00-2019), the CAISO's Amendment 60 proceeding (Docket Nos. ER04-835 and EL04-103), and in SCE's Existing Transmission Contract Rate Case (Docket No. ER08-1353). In addition, I have submitted testimony in several of SCE's Reliability Services ("RS") cases (Docket Nos. ER02-238, ER03-142, ER04-122, ER04-890, ER04-1176, ER04-1209, ER05-410, ER05-763, ER05-1154, ER06-259, ER07-75, ER08-82, ER09-95, ER10-105, ER11-1934, ER12-201, ER13-227, ER14-222, and ER16-174).

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the details of SCE's proposed Formula Rate, including the overall structure of the formula and the annual update process, as set forth in the proposed Formula Rate Spreadsheet and Protocols. Additionally, my testimony will support SCE's proposed Base Transmission Revenue Requirements ("Base TRR") and associated retail and wholesale transmission rates to be effective on January 1, 2018 developed utilizing the proposed Formula Rate Spreadsheet populated with inputs (Exhibit No. SCE-4).

Q. What portions of the proposed Formula Rate Spreadsheet and Formula Rate Protocols will you be sponsoring?

A. I am sponsoring Schedule 1 (Base TRR), except for the Cash Working Capital calculation on Line 7, and the Return and Capitalization, Other Taxes, and Income Taxes components on Lines 19-65, Schedule 2 (Incremental Forecast Period TRR), Schedule 3 (True Up Adjustment), Schedule 4 (True Up TRR), Lines 1-38 of Schedule 14 (Incentive Plant), Schedule 15 (Incentive Adder), Schedule 24 (CWIP TRR), Schedule 29 (Wholesale TRRs), Schedule 30 (Wholesale Rates), Schedule 32 (Gross Load), and the Formula Rate Protocols in their entirety. Additionally, I am sponsoring the wholesale aspects of Cost of Service Statements BG, BH, and BL.

II. OVERVIEW OF SCE'S PROPOSED FORMULA RATE

Q. Please describe the overall structure of SCE's proposed Formula Rate.

A. SCE's proposed Formula Rate determines SCE's Base TRR according to the following formula:

Base TRR = Prior Year TRR +
Incremental Forecast Period TRR +
True Up Adjustment

Additionally, as explained below, under certain circumstances as defined in SCE's Formula Rate Protocols, SCE may include a Cost Adjustment in the determination of the Base TRR.

Q. What is the Prior Year?

A. The Prior Year is the most recent calendar year at the time when an Annual Update informational filing is submitted. It is the period for which SCE will have recorded costs that will be reflected in the Base TRR for the upcoming year. For this filing, as it is being made in 2017, the Prior Year is 2016.

Q. What is the Rate Year?

A. The Rate Year is the year for which the Base TRR and associated rates are being set in an Annual Update filing which is the upcoming calendar year following an Annual Update submission. For this filing, as it is being made in 2017, the Rate Year is 2018.

Q. What is the Forecast Period?

A. The Forecast Period is the 24-month period beginning the January after the Prior Year and extending through the end of the Rate Year. It is the period of time for which forecasts of additions to Plant in Service and CWIP are made in order to develop the Incremental Forecast Period TRR (which is based on the 12-month portion of the forecast that corresponds to the Rate Year). For this filing, the Forecast Period is January 2017 through December 2018.

Q. Please provide a brief description of each of the components of the Base TRR.

A. The Base TRR is composed of the Prior Year TRR, the Incremental Forecast Period TRR and the True Up Adjustment. The Prior Year TRR represents SCE's cost of service associated with the Prior Year, reflecting End of Year ("EOY") values with respect to Rate Base. It is calculated based on cost inputs from SCE's FERC Form 1 for that Prior Year, as supplemented by documented SCE records. Since the Prior Year TRR is calculated using EOY values for Rate Base, it represents SCE's cost of service at the end of the Prior Year with respect to Rate Base. The components of the Prior Year TRR are described in detail in Section III below.

The Incremental Forecast Period TRR ("IFPTRR") represents the expected incremental amount of transmission costs that SCE will incur during the Rate Year, as compared to that amount included in the Prior Year TRR. SCE's actual transmission costs are generally expected to be higher during the Rate Year than they were during the Prior Year due to Rate Base growth. The IFPTRR is included in the determination of the Base TRR to ensure that the rates being assessed during the Rate Year reflect the costs that are forecast to be incurred during that period. The determination of the IFPTRR is described in Section IV below.

The True Up Adjustment is included in the Base TRR to ensure that over time SCE collects no more and no less than its actual costs of owning and operating its transmission system. It is calculated based on the cumulative over or undercollection of actual costs at the end of the Prior Year, less an amount reflecting any amount already being returned or collected from customers in the current year. SCE's actual costs incurred during the Prior Year are defined by the "True Up TRR." The True Up TRR is very similar to the Prior Year TRR, with the difference being that Rate Base is calculated on an average over the year basis (either an average of the Beginning of Year ("BOY") and EOY values, or a 13-month average) rather than an end-of-year basis. Generally, the major Rate Base items are calculated on 13-month average year basis, including specifically ISO Transmission Plant, ISO Accumulated Depreciation, Prepayments, Materials and Supplies, and CWIP Plant. The details of the calculation of the True Up Adjustment are presented in Section VI below, while the details of the True Up TRR are presented in Section V.

Q. Do the values of the Prior Year TRR or the IFPTRR affect the costs that SCE will ultimately recover pursuant to the proposed Formula Rate?

A. No. It is only the True Up TRR that determines the amount of costs that SCE will ultimately recover pursuant to the proposed Formula Rate. The True Up Adjustment (Schedule 3 of the Formula Spreadsheet), which is based on a comparison of actual revenues to actual costs (as determined by the True Up TRR) ensures that SCE recovers over time its actual costs of owning and operating its transmission system. If SCE is cumulatively over or under collected at the end of the Prior Year, that difference is kept track of in the True Up Adjustment mechanism, and future rates are adjusted higher or lower as appropriate in the Rate Year through the True Up Adjustment component of the Base TRR.

The purpose of the Prior Year TRR and the IFPTRR components of the Base TRR is to determine a projection of the Base TRR that SCE will experience during the Rate Year, so that SCE's transmission rates may be set at a level that approximates SCE's actual costs during the Rate Year. The relationship between these inputs can be illustrated if we assume a perfectly accurate projection. That is, if the sum of the Prior Year TRR and the IFPTRR equals the True Up TRR amount ultimately obtained during that Rate Year (and assuming that SCE's forecast sales are accurate), then SCE's retail transmission rates will generate retail transmission revenues during the Rate Year equal to SCE's True Up TRR (with the True Up Adjustment component of the Base TRR returning or collecting an amount related to any previous over or undercollections).

Q. What is the "Cost Adjustment" provision, and under what circumstances would SCE include it in the determination of the Base TRR?

A. The Cost Adjustment component of the Base TRR allows SCE to reflect in the Base TRR the effect of known and significant cost impacts, either positive or negative, that differ from those that are included in the Prior Year TRR. The circumstances under which the Cost Adjustment may be utilized are set forth in the Formula Rate Protocols, Section 1, and are summarized as follows:

1) If SCE experiences a discrete cost of service item, that is not expected to recur in the Rate Year, anytime between the beginning of the Prior Year and the September 30 preceding the Annual Update filing (*i.e.*, a 21-month window) with a magnitude of greater than 3% of SCE's Base TRR, then a Cost Adjustment shall be included in the Base TRR.
2) If the discrete cost of service item occurred during the Prior Year, then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude but of the opposite sign as the discrete cost of service item.

3) If the discrete cost of service item occurred during the first nine months of the filing year (year the before the Rate Year), then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude and sign as the discrete cost of service item.

The Cost Adjustment amount may be either a positive or negative component of the Base TRR. The purpose of including this provision is to align SCE's Base TRR and rates with SCE's actual costs over time, and help assure that SCE's True Up Adjustment amounts are minimized.

Q. Why does the sign of the Cost Adjustment differ depending on whether the discrete cost of service item was experienced in the Prior Year or the first nine months of the filing year?

A. Because the consequences of the two are different in terms of how they will affect any over or under recovery during the upcoming Rate Year, or during the current filing year (previous Annual Update Rate Year). In the case where the cost item was experienced in the Prior Year, and will not recur in the Rate Year, then if that item is allowed to contribute to the TRR during the Rate Year, there will be a built in overcollection during that year associated with that item (if the item was a positive cost). That is because when the True Up TRR is determined for the Rate Year (in the Annual Update two years later), it will not include that cost. Setting the Cost Adjustment equal to the negative of the amount of the cost item in effect cancels out that built in overcollection.

If, on the other hand, the cost item occurs in the first nine months of the filing year, then that cost was not in the Prior Year TRR in the first place. So, all else equal, there will not be a built in ovecollection during the Rate Year associated with that cost. But there will be a contribution to an undercollection during the filing year, since that amount would not have been included in the previous Annual Update setting the TRR and rates for the current year. That undercollection will materialize during the next Annual Update when actual costs and actual revenues are compared for the current year. Including Cost Adjustment component of the Base TRR (positive in the case of a positive experienced discrete cost item, and negative in the case of a negative experienced discrete cost item) allows the rates to be adjusted immediately in this Rate Year rather than waiting for the subsequent Rate Year as would otherwise occur.

Q. Why is the Prior Year TRR determined based on End-of-Year Rate Base values?

A. The Prior Year TRR is determined using EOY Rate Base values to make it more likely that the sum of the Prior Year TRR and the IFPTRR will equal the costs that SCE will actually incur during the Rate Year. Using an EOY Rate Base is a method of taking a "snapshot" of SCE's costs at the EOY value, at least with respect to return on capital costs. When the Prior Year TRR is added to the IFPTRR (which represents SCE's expected incremental costs relative to the end of the Prior Year), that sum should then serve as a reasonable forecast of the actual costs that SCE will incur during the Rate Year, as determined by the True Up TRR (described in Section V below).

Q. Is SCE proposing a termination date for the proposed Formula Rate?

A. No. SCE is not proposing a termination date, and accordingly this proposed Formula Rate could operate indefinitely assuming Commission acceptance and approval. However, SCE reserves the right, as it currently has, to file pursuant to Section 205 of the Federal Power Act to revise the method of calculating its Base Transmission Revenue Requirement. For example, SCE could propose at any time in the future another formula rate or a stated transmission rate, in which case this proposed Formula Rate would be superseded upon Commission acceptance of the new proposed Base TRR mechanism.

Q. In the event that the proposed Formula Rate were to terminate at some future date, how does the proposed Formula Rate handle any remaining amount of uncollected or overcollected revenues?

A. In the event that the proposed Formula Rate expires at some future date, the proposed Formula Rate includes a provision to determine a Final True Up Adjustment. The amount of the Final True Up Adjustment will be determined by comparing monthly revenues received to monthly costs, and including interest to the termination date of the formula rate, to determine the final over or under collected balance through the termination date of the proposed Formula Rate. SCE will be entitled and required to include the amount of this Final True Up Adjustment (either positive or negative) in SCE's successor transmission rates. Inclusion of a Final True Up Adjustment provision in the proposed Formula Rate is necessary to ensure that SCE recovers its transmission costs over the term of the formula rate.

Q. Please describe the annual update process.

A. There are three key dates in the annual update process: 1) By each June 15, SCE will post a Draft Annual Update on its website; 2) by each December 1, SCE will file the Annual Update at the Commission with a revised Base TRR and associated transmission rates for the upcoming Rate Year; and 3) each January 1 the revised Base TRR and associated transmission rates calculated pursuant to the proposed Formula Rate will become effective. These key dates in the Annual Update process are set forth in the Formula Rate Protocols, Section 3.

The Annual Update filing made by December 1 will consist of the Formula Rate Spreadsheet populated with inputs for the Prior Year from SCE's FERC Form 1, or other documented SCE sources, as well as forecasts of additions to ISO Transmission Plant, and Construction Work In Progress

(“CWIP”), during the Forecast Period.

In order to provide interested parties time to review SCE’s Annual Update, SCE proposes to make available for review the Draft Annual Update by June 15 each year. The Draft Annual Update will include substantially all of the same information required to be included in the upcoming Annual Update, so that the Base TRR presented in the Draft Annual Update should be the same Base TRR that SCE ultimately files in the Annual Update filing by December 1, unless input errors are identified and corrected before the Annual Update is filed.

The purpose of the five and one-half month period following the availability of the Draft Annual Update and the filing of the Annual Update is to allow interested parties to review SCE’s inputs to the Formula Rate Spreadsheet, ask questions and send SCE reasonable data requests if they are unclear about any part of the Draft Annual Update, or believe that particular inputs are incorrect, or if they disagree with a forecast that SCE has made. If interested parties do identify errors in inputs that SCE made to the proposed Formula Rate in the Draft Annual Update, or propose changes that SCE believes are correct and appropriate, SCE can make corrections and include the proposed changes in the Annual Update filing. SCE’s Formula Rate Protocols describe in detail the process for review and the provisions for discovery during this period, which I cover in Section XI below.

III. THE PRIOR YEAR TRR

Q. What costs are included in the Prior Year TRR?

A. The Prior Year TRR includes the following cost components:

1) Return on Capital
2) Prior Year Incentive Adder
3) Depreciation Expense
4) Operation and Maintenance Expense

5) Administrative and General Expense
6) Income Taxes
7) Other Taxes
8) Revenue Credits
9) Regulatory Debits
10) Network Upgrade Interest Expense
11) Gains and Losses on Transmission Plant Held for Future Use - Land
12) Abandoned Plant Amortization Expense.
13) Franchise Fees and Uncollectibles Expenses

I will describe each of these thirteen items in turn.

Q. Please describe the Return on Capital component of the Prior Year TRR.

A. The Return on Capital component of the Prior Year TRR represents SCE's annual capital costs, including the Cost of Long Term Debt, the Cost of Preferred Stock, and the Cost of Equity. Return on Capital is calculated in Schedule 1 of the Formula Rate Spreadsheet, Lines 37 to 56. Dr. Hunt describes the details of the calculation of the Return on Capital in Exhibit No. SCE-17.

Q. Please describe the Prior Year Incentive Adder component of the Prior Year TRR.

A. The Prior Year Incentive Adder quantifies the additional amount of annual revenue that SCE should receive due to ROE incentives approved by the Commission, related to the amount of Rate Base in the Prior Year that has received these ROE incentives. The Prior Year Incentive Adder is calculated in Schedule 15 of the Formula Rate Spreadsheet. I discuss in detail how the Prior Year Incentive Adder is calculated in Section VIII.

Q. Please describe the Depreciation Expense component of the Prior Year TRR.

A. Depreciation Expense represents the annual amortization of invested capital included in SCE's Rate Base used to determine its Base TRR. Capital invested in long-lived assets (including the cost to retire the assets) is expensed over the expected useful life of the asset through Depreciation Expense. Depreciation Expense includes components related to plant booked as Transmission, Distribution, General, and Electric Miscellaneous Intangible Plant ("Intangible Plant"). Depreciation Expense is calculated in Schedule 17 of the Formula Rate Spreadsheet. Mr. Gunn describes the details of the determination of Depreciation Expense in Exhibit No. SCE-7.

The Depreciation Expense amount in the Prior Year TRR is calculated for retail customers. An adjustment to the retail depreciation expense for Wholesale customers is determined and included as one component of the "Wholesale Difference to the Base TRR," which I explain below in Section IX.

Q. Please describe the Operation and Maintenance Expense component of the Prior Year TRR.

A. Operation and Maintenance Expense ("O&M Expense") represents the costs that SCE incurs operating and maintaining its ISO transmission facilities (whose costs are included in the Base TRR). O&M Expense is calculated in Schedule 19 of the Formula Rate Spreadsheet. Mr. Moon describes the details of the determination of O&M Expense in Exhibit No. SCE-9.

Q. Please describe the Administrative and General Expense component of the Prior Year TRR.

A. Administrative and General Expense ("A&G Expense") represents the costs of SCE's administrative and general corporate expenses, which support the operation of the entire company, that are allocated to the ISO transmission function and therefore are recovered through the Base TRR. A&G Expense is calculated on Schedule 20 of the Formula Rate Spreadsheet. Mr. Mindess describes the determination of A&G Expenses in his testimony, Exhibit No. SCE-12.

Q. Please describe the Income Taxes component of the Prior Year TRR.

A. Income Taxes represent the Federal and State income taxes associated with SCE's Return on Capital in the Prior Year TRR. Income Taxes are determined pursuant to a formula, as presented in the Formula Rate Spreadsheet, Schedule 1, Lines 57 to 65. Mr. Lopez provides a detailed description of the formulary determination of Income Taxes in Exhibit No. SCE-11.

Q. Please describe the Other Taxes component of the Prior Year TRR.

A. Other Taxes are the sum of Payroll Taxes Expense and Property Taxes, and are calculated in the Formula Rate Spreadsheet in Schedule 1, Lines 19 to 36. Payroll Taxes Expense is an allocated portion of Total Electric Payroll Taxes Expense using the Wages and Salaries Allocation Factor ("W&S AF"), in accordance with Commission policy. The proposed Formula Rate reduces Total Electric Payroll Tax Expense by SCE's capitalized overhead amount before applying the W&S AF, to reflect the fact that SCE capitalizes a portion of the Electric Payroll Tax Expenses, as stated in FERC Form 1. Property Taxes are an allocated portion of Total Property Taxes, using the Transmission Plant Allocation Factor. Mr. Lopez provides a detailed description of the determination of Other Taxes in Exhibit No. SCE-11.

Q. Please describe the Revenue Credits component of the Prior Year TRR.

A. Revenue Credits are revenues that SCE receives that are attributable to the transmission assets under the ISO's Operational Control. Revenue Credits are calculated in Schedule 21 of the Formula Rate Spreadsheet. Ms. Kim describes the details of the determination of Revenue Credits in Exhibit No. SCE-13.

Q. Please describe the Regulatory Debits component of the Prior Year TRR.

A. Regulatory Debits are an amortization of "Other Regulatory Assets/Liabilities" related to SCE's ISO transmission facilities debited to FERC Account 407.3.

Regulatory Debits, as well as Other Regulatory Assets/Liabilities, are by definition set to $0 initially. In order to recover any costs pursuant to this category of costs through the Prior Year TRR, SCE is required to make a Section 205 filing to the Commission and receive Commission approval. The purpose of this cost category is to provide a mechanism for any regulatory liabilities imposed on SCE by ratemaking actions of regulatory agencies to be recovered through rates. Regulatory Debits are calculated in Schedule 23 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of Regulatory Debits in Exhibit No. SCE-15.

Q. Please describe the Network Upgrade Interest Expense component of the Prior Year TRR.

A. Network Upgrade Interest Expenses are related to refundable upfront payments that generators make for network upgrades. When generators make such upfront payments, SCE must return the upfront payment over five years, including interest. Network Upgrade Interest Expense is the interest expense component of the payment to the generator. Network Upgrade Interest Expense is related to one of the components of Rate Base, Network Upgrade Credits. Network Upgrade Interest Expense is calculated in Schedule 22 of the Formula Rate Spreadsheet. Mr. Ocegueda discusses Network Upgrade Interest Expense in his testimony, Exhibit No. SCE-15.

Q. Please describe the Gains and Losses on Transmission Plant Held for Future Use – Land component of the Prior Year TRR.

A. Gains and Losses on Transmission Plant Held for Future Use – Land is included as a component of the Prior Year TRR because Commission policy requires such gains or losses on the land component of Transmission Plant Held for Future Use to be flowed back to ratepayers. However, gains or losses on non-land Transmission Plant Held for Future Use are not required to be flowed back to ratepayers. The Commission stated this policy in its order on the formula rate of San Diego Gas and Electric in Docket No. ER07-284 (118 FERC ¶ 61,073 P 28 (2007)). Gains and Losses on Transmission Plant held for Future Use -- Land is calculated in Schedule 11 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of the Gains and Losses on Transmission Plant held for Future Use – Land in his testimony, Exhibit No. SCE-15.

Q. Please describe the Abandoned Plant Amortization Expense component of the Prior Year TRR.

A. Abandoned Plant Amortization Expense is incurred in the event that SCE receives a Commission Order approving recovery of abandoned plant costs. Costs recovered through this cost category are the annual amortization of the abandoned plant costs. Abandoned Plant costs may also be included in Rate Base through the Abandoned Plant component of Rate Base. In order for SCE to recover any Abandoned Plant Amortization Expense costs through this proposed Formula Rate, SCE must make a Section 205 filing to the Commission requesting approval, and receive approval from the Commission. Abandoned Plant Amortization Expense is calculated in Schedule 12 of the Formula Rate Spreadsheet. Mr. Ocegueda describes the determination of the Abandoned Plant component of Rate Base as well as Abandoned Plant Amortization Expense in his testimony, Exhibit No. SCE-15.

Q. Please describe the Franchise Fees and Uncollectibles components of the Prior Year TRR.

A. Franchise Fees represent the payments that SCE makes to municipal entities for the right to locate facilities within the municipality. The proposed Formula Rate determines Franchise Fees Expense by applying the Franchise Fee Factor, as approved by the California Public Utilities Commission (“CPUC”), to the total of the above-mentioned 12 cost components. Uncollectibles Expenses represent billed revenue that SCE does not collect from its retail customers. The proposed Formula Rate determines Uncollectibles Expense by applying the Uncollectibles Expense Factor approved by the CPUC to the total of the above-mentioned 12 cost components. Franchise Fees and Uncollectibles expense are calculated on Lines 79 and 80, respectively, of Schedule 1 of the Formula Rate Spreadsheet. Mr. Mindess describes the determination of the Franchise Fees and Uncollectibles Expense amounts in his testimony, Exhibit No. SCE-12.

Q. Is SCE proposing any changes to the calculation of these thirteen cost components of the Prior Year TRR compared to the Original Formula Rate?

A. Yes. The proposed revisions to these thirteen cost components are summarized in Exhibit No. SCE-5 ("Formula Spreadsheet Revisions").

Q. Do these thirteen components of costs that SCE proposes to include in the Prior Year TRR reflect costs that should be included in a transmission owner's TRR?

A. Yes. These thirteen TRR cost components are all costs that SCE incurs related to providing transmission service over SCE's transmission facilities that have been placed under the Operational Control of the ISO. Accordingly, they all should be included in the Prior Year TRR.

Q. Does the proposed Formula Rate Spreadsheet calculate a transmission revenue requirement attributable only to CWIP in Rate Base costs?

A. Yes. Schedule 24 of the proposed Formula Rate Spreadsheet calculates a CWIP TRR associated with the CWIP component of Rate Base (associated only with the projects for which SCE received a Commission Order approving CWIP in Rate Base). The CWIP TRRs are calculated for both the Prior Year

TRR and the Incremental Forecast Period TRR, and are calculated on both a retail (Line 79) and a wholesale (Line 88) basis. The primary purpose of calculating the CWIP TRR is informational, so that users of the proposed Formula Rate can ascertain what portion of SCE's total Base TRR is associated with CWIP in Rate Base. However, the wholesale CWIP TRR is also used as a component of the High and Low Voltage calculation performed on Schedule 29 (Line 9, Columns 2 and 3, respectively). SCE is not proposing to revise any aspect of Schedule 24, other than to remove certain projects that will no longer contribute to the calculation of the CWIP TRR (Eldorado-Ivanpah and Lugo-Pisgah).

IV. THE INCREMENTAL FORECAST PERIOD TRR

Q. Please describe how the Incremental Forecast Period TRR ("IFPTRR") is calculated.

A. The IFPTRR is calculated in Schedule 2 of the proposed Formula Rate by applying annual fixed charge rates to forecast incremental amounts of Net Plant and CWIP (relative to the end of the Prior Year amount) expected to be in place by the end of the Forecast Period (equivalently, through the end of the Rate Year). The IFPTRR treats additions to regular (non-CWIP) plant in service additions differently than CWIP additions. This is because when a plant addition is placed in service, it begins incurring operations and maintenance costs, whereas CWIP does not.

Accordingly, the IFPTRR is calculated as the sum of two components:

1) Projected cumulative additions to plant in service, less depreciation, through the Forecast Period (determined on a 13-Month average basis over the Rate Year), multiplied by an Annual Fixed Charge Rate ("AFCR"); and
2) Cumulative CWIP additions through the Forecast Period (again

on a 13-Month average basis) multiplied by the AFCR for CWIP ("AFCRCWIP").

Both the net plant in service and the CWIP additions are measured relative to the end-of-year values for the Prior Year, so that the additions included in the calculation of the IFPTRR are only incremental to amounts that were already included in the calculation of the Prior Year TRR.

The AFCR represents the annual TRR costs associated with an incremental dollar of Net Plant in service. The AFCR is calculated by dividing the Prior Year TRR, excluding 75% of O&M and A&G costs, and exclusive of CWIP-related costs, by the Net Plant used in determining the Prior Year TRR. The exclusion of 75% of O&M and A&G costs is an adjustment to reflect that newer facilities are likely to incur less than average maintenance expenses relative to other SCE plant. The AFCRCWIP represents the capital costs (including income taxes) associated with CWIP in Rate Base. The AFCRCWIP is calculated based on the Weighted Cost of Long-Term Debt, and the Weighted Cost of Common and Preferred Stock. The Weighted Cost of Common and Preferred Stock is multiplied by a tax gross up factor of (1 / (1 - Composite Tax Rate)), and added to the Weighted Cost of Long Term Debt.

Q. Is SCE proposing to make any revisions to the calculation of the Incremental Forecast Period TRR on Schedule 2 compared to the Original Formula Rate?

A. No, the Schedule 2 calculation of the Incremental Forecast Period TRR is unchanged from the Original Formula Rate.

Q. What is the amount of the Incremental Forecast Period TRR proposed for rates effective January 1, 2018?

A. The proposed amount of the Incremental Forecast Period TRR is $109,324,746. *See* Schedule 2, Line 82 of the populated Formula Rate Spreadsheet, Exhibit No. SCE-4.

V. THE TRUE UP TRR

Q. What is the True Up TRR?

A. The True Up TRR represents the actual amount of costs that SCE incurred in the Prior Year, with all Rate Base items determined on an average basis, consistent with Commission cost of service policy for the determination of actual costs in a year. The primary difference between the True Up TRR and the Prior Year TRR is that the Prior Year TRR Rate Base components are determined on an EOY basis, while the True Up TRR Rate Base components are based on average basis (either 13-month average or average of BOY and EOY, shown on the proposed Formula Rate Spreadsheet Schedule 4, Lines 1-17 under the “Calculation Method” column). It includes the same cost-of-service elements as the Prior Year TRR. Since Rate Base is calculated on an average basis over the year for the True Up TRR, rather than at the end of year as in the Prior Year TRR, the Return on Capital and Income Tax expense components of the True Up TRR will differ from the amounts in the Prior year TRR.

An additional difference between the True Up TRR and the Prior Year TRR is that expenses related to underlying stated values (see the description of a stated value in Section XII) in the proposed Formula Rate are synchronized so that the determination of the True Up TRR will be calculated based on the amount of the stated value that was in effect during the Prior Year, in those cases where the calculation of the Prior Year TRR is based on the tariff values for the stated value in effect at the time of the Annual Update. The expense items that are subject to synchronization through adjustments to the Prior Year TRR amounts are: 1) The Cost of Capital Rate (to reflect any change in Return on Equity during the Prior Year, see Schedule 4, Line 19 and Instruction 1), and 2) the Authorized PBOPs Expense Amount (see Schedule 20, Note 3). Depreciation expense is also calculated based on stated values (set forth in Schedule 18), but since the amount of Depreciation Expense included in the Prior Year TRR already reflects Commission-approved Depreciation Rates in effect each month of the Prior Year (see Schedule 17, Lines 17a-17m), no further adjustment to the True Up TRR is required to ensure that the amount of depreciation expense reflected in the True Up TRR correctly reflects Commission-approved rates that were in effect during the Prior Year.

Q. Is SCE proposing to make any revisions to the calculation of the True Up TRR on Schedule 4 compared to the Original Formula Rate?

A. No, the calculation of the True Up TRR on Schedule 4 of the proposed Formula Rate Spreadsheet is the same as the Original Formula Rate. However, four non-substantive revisions are proposed for Schedule 4:

1) The PBOPs True Up TRR adjustment is eliminated;
2) Instruction 1, Line a is yellow-shaded to allow for the ROE at the beginning of the year to be input;
3) The Schedule line numbers are renumbered to eliminate non-numeric lines 15a and 27a; and
4) Note 1 from the Original Formula Rate is eliminated as it is no longer relevant (relating to CWIP for Tehachapi Segment 8, which is now in service).

Q. Why is the PBOPs True UP TRR Adjustment eliminated in Schedule 4 of the proposed Formula Rate Spreadsheet?

A. SCE is proposing to remove that adjustment from Schedule 4 and move an equivalent adjustment to Schedule 20, Note 3. This will simplify the mechanism for ensuring that the PBOPs expense component of the True Up TRR is based on the Authorized PBOPs Expense Amount that was in effect during the Prior Year.

Q. Why is Instruction 1, Line a of Schedule 4 proposed to be changed to a yellow-shaded input?

A. SCE is proposing to yellow-shade that line to ensure that, in the event that the ROE that was in effect during the Prior Year differs from that which is in effect at the time of the Annual Update filing (and therefore stated on Schedule 1, Line 50), the Schedule 4 True Up TRR calculation can be calculated based on the average ROE that was in effect during the Prior Year regardless of when the ROE may have changed.

Q. What is the amount of the True Up TRR for the 2016 Prior Year in the proposed Formula Rate?

A. The proposed True Up TRR for the 2016 Prior Year rates effective January 1, 2018 is $1,062,934,400, as shown on Line 46 of Schedule 4. However, as explained in Section VI below, since the True Up TRR for the 2016 Prior Year must be calculated pursuant to the Original Formula Rate, an adjustment entry is made to the True Up Adjustment to ensure that SCE only recovers actual costs as determined under the Original Formula Rate for the 2016 year. See Schedule 3, Line 23, Column 4 of the populated proposed Formula Rate Spreadsheet, Exhibit No. SCE-4 for this adjustment entry in the amount of -$39,484,975.

VI. THE TRUE UP ADJUSTMENT

Q. Please describe how the True Up Adjustment is determined.

A. The True Up Adjustment component of the Base TRR ensures that over time SCE collects exactly its costs of owning and operating its transmission assets under the Operational Control of the ISO, as measured by the True Up TRR. The True Up Adjustment mechanism is set forth in Schedule 3 of the proposed Formula Rate Spreadsheet. It both keeps track of the cumulative over or under collection of revenues since the inception of the proposed Formula Rate, and determines the True Up Adjustment component of the Base TRR.

Q. What is the purpose of the True Up Adjustment component of the Base TRR?

A. The purpose of the True Up Adjustment is to set SCE's Base TRR at a level that will recover through retail transmission rates an amount which will return SCE's "Cumulative Excess or Shortfall in Revenue with Interest" amount close to $0 by the end of the Rate Year. That amount will not be known until the Annual Update two years following the determination of the current Annual Update, since there is a two-year lag between the Prior Year and the Rate Year.

Q. How is the cumulative over or under collection of transmission revenues calculated in Schedule 3?

A. Schedule 3 of the Formula Spreadsheet contains a module that compares the monthly True Up TRR (Column 2, Lines 12 to 23) to the actual retail transmission revenues attributable to the proposed Formula Rate (Column 3, Lines 12 to 23) for each month of the Prior Year. Interest is applied monthly based on the interest rate specified in FERC regulations (18 C.F.R. §35.19) to determine the "Cumulative Excess or Shortfall in Revenue with Interest" at the end of the Prior Year (Line 23, Column 9). That amount represents the cumulative overcollection or undercollection that must be returned to or recovered from SCE's retail transmission customers through future retail transmission rates.

Q. How is the "Cumulative Excess or Shortfall in Revenue with Interest" from the previous Annual Update considered in the determination of the current Annual Update "Cumulative Excess or Shortfall in Revenue with Interest"?

A. The amount of the "Cumulative Excess or Shortfall in Revenue with Interest" from the previous Annual Update is required to be entered into the calculation as the beginning balance. This is accomplished by entering the "Cumulative Excess or Shortfall in Revenue with Interest" amount from the previous Annual Update on Line 11, Column 4 of Schedule 3 for the current Annual Update. Accordingly, the "Cumulative Excess or Shortfall in Revenue with Interest" in the current Annual Update Line 23, Column 9 will reflect the entire history of any over or under collections of actual costs through the proposed Formula Rate (including the term of the Original Formula Rate), including interest.

Q. How is the True Up Adjustment amount determined?

A. The True Up Adjustment is defined as the current "Cumulative Excess or Shortfall in Revenue with Interest" minus the previous Annual Update True Up Adjustment. Projected interest is applied to that amount at the most recent FERC Interest Rate to the middle of the Rate Year (*see* Line 29 of Schedule 3).

Q. Why does the current Annual Update True Up Adjustment include the True Up Adjustment from the previous Annual Update?

A. Based on SCE's experience with the Original Formula Rate, it was observed that the True Up Adjustment as defined and implemented in the Original Formula Rate was oscillating and not returning the "Cumulative Excess or Shortfall in Revenue with Interest" amount to close to $0 by the end of the

Rate Year (the True Up Adjustment in the Original Formula Rate was essentially set equal only to the "Cumulative Excess or Shortfall in Revenue with Interest"). Specifically, the magnitude of the True Up Adjustment amounts included in the first five Annual Updates with a True Up of actual costs to actual revenues (*i.e.*, beginning with the 2012 year and through the 2016 year) were: negative $68.2 million, negative $66.9 million, $13.3 million, $94.2 million, and $59.6 million.

Upon examination of the underlying time-series math, it was determined that the root cause of this was due to the two-year lag between the Rate Year and the Prior Year. Any initial over or under collection of revenues was reflected in rates twice before the True Up Adjustment from the first year could take effect. This issue was only a ratesetting issue, and did not affect the Original Formula Rate tracking of the "Cumulative Excess or Shortfall in Revenue with Interest" amounts. However, SCE sought to identify a better definition of the True Up Adjustment amount so that the True Up Adjustments will not oscillate as much as they did under the Original Formula Rate. The solution that SCE has identified is to include a subtraction of the previous Annual Update True Up Adjustment in the current Annual Update True Up Adjustment. This revision will work since it prevents double recovery of any over or under recovery amounts before the True Up Adjustment affects actual revenues.

Q. Why is interest applied to the middle of the Rate Year in the proposed new True Up Adjustment formula?

A. Interest is applied to the middle of the Rate Year to set the True Up Adjustment at a level that is most likely to result in the "Cumulative Excess or Shortfall in Revenue with Interest" to $0 at the end of the Rate Year. Again, this is only a ratesetting adjustment; it will not affect the recovery of actual costs, as reflected by the amount of SCE's "Cumulative Excess or Shortfall in Revenue with Interest" at the end of the Prior Year.

Q. What is the purpose of a One-Time Adjustment?

A. A One Time Adjustment is an adjustment to costs in an Annual Update filing that relates to a period previous to the Prior Year for that Annual Update. One Time Adjustments are required to reflect any errors that are found in the determination of a True Up TRR relating to a year previous to the current Annual Update Prior Year. See Section 3.d.8 of the Formula Rate Protocols for a description of the circumstances under which a One Time Adjustment is required. For example, suppose that during the development of an Annual Update during year X that is determining the True Up TRR for the Prior Year of X-1, it is determined that an error that affected the True Up TRR for year X-2 in the amount of -$100,000 had occurred. This would be reflected by including a One Time Adjustment of -$100,000 in the current Annual Update filing (plus the applicable interest).

Q. How will One-Time Adjustments be quantified and reflected in an Annual update filing?

A. When an error affecting the True Up TRR for a period before the current Prior Year is identified, the True Up TRR for the period of time during which the error occurred is rerun to identify the change in the True Up TRR associated with that calendar year. Interest is then applied to January of the current Prior Year to determine the One Time Adjustment. This amount is then entered as a One Time Adjustment on Line 12 of Schedule 3 of the original Annual Update Formula Rate Spreadsheet.

Q. Does the proposed Formula Rate determination of the Base TRR for 2018 include any One Time Adjustments?

A. Yes, the proposed Formula Rate determination of the Base TRR for 2018 includes a One Time Adjustment of negative $77,804 (*see* Schedule 3, Line 12, Column 4 of Exhibit No. SCE-4. Ms. Kim supports the development of this One Time Adjustment in her testimony, Exhibit No. SCE-13.

Q. If the proposed Formula Rate expires, is there a provision for dealing with any final over or undercollection of SCE's True Up TRR costs?

A. Yes, the proposed Formula Rate contains a Final True Up provision that will ensure that SCE will recover the actual costs incurred over the period of time that the proposed Formula Rate is in effect, as determined by the True Up TRR. See Section 4 of the Formula Rate Protocols, as well as Section 5 of Schedule 3, Lines 32-35.

VII. INCORPORATION OF FINAL TRUE UP ADJUSTMENT AMOUNTS FROM THE ORIGINAL FORMULA RATE FOR 2016 AND 2017 IN THE PROPOSED BASE TRR FOR RATE YEARS 2018 AND 2019

Q. Was there a Final True Up Adjustment provision in SCE's Original Formula Rate?

A. Yes, pursuant to the Original Formula Rate Protocols Section 4, SCE is required to calculate a Final True Up Adjustment to recover or return in SCE's successor transmission rates any amount of the cumulative over or undercollection of the True Up TRR relating to the period of time the Original Formula Rate was in effect:

> "After expiration of the Formula Rate, SCE shall calculate a Final True Up Adjustment. The Final True Up Adjustment shall cover the period of time ending on the expiration of the Formula Rate and beginning on the day after the period covered by the most recent Annual True Up Adjustment that was included in the Base TRR. For example, if the Formula Rate terminates as scheduled on December 31, 2017, SCE will determine a Final True Up Adjustment in 2018 for calendar year 2017. Except as otherwise stated in this paragraph, the Final True Up Adjustment shall be determined using the same calculation methodology as the Annual True Up Adjustment.
>
> Interest included in the Final True Up Adjustment shall be calculated through the date of the termination of the Formula Rate (or, in the event of a partial determination of the Final True Up Adjustment, through the end of the period covered by that partial determination). The Final True Up Adjustment shall be subject to the procedures described in Section 3 of the Protocols. If the Final True Up Adjustment reflects an undercollection by SCE, then SCE shall be entitled and required to recover the amount of this Final True Up Adjustment in SCE's successor transmission rates to the Formula Rate. If the Final True Up Adjustment reflects an overcollection by SCE, then SCE shall be required to refund the amount of this Final True Up Adjustment to its customers."

Q. What was the purpose of the Original Formula Rate Final True Up Adjustment provision?

A. To ensure that SCE will recover an amount of transmission revenue equal to SCE's actual FERC jurisdictional transmission costs, as determined by the True Up TRRs determined by the Original Formula Rate, over the term of the Original Formula Rate.

Q. For what period of time will a determination of a Final True Up Adjustment relating to SCE's Original Formula Rate be required?

A. For the calendar years 2016 and 2017. The years 2015 and before were already reflected in previous Annual Updates submitted pursuant to the Original Formula Rate. Additionally, in the event that this proposed Formula Rate does not become effective on January 1, 2018 as SCE has requested, a Final True Up Adjustment will be required to cover any period of time beginning January 1, 2018 through the date this proposed Formula Rate becomes effective.

Q. Is the cumulative over or undercollection of actual transmission costs for the 2016 and 2017 years known as of the date of this filing?

A. No, only the cumulative over or undercollection of actual transmission costs through the end of 2016 is known as of the date of this filing. Currently, the True Up TRR calculated under the Original Formula Rate is known for 2016, and has been filed in the TO12 Annual Update submitted contemporaneously with this filing. The True Up TRR for 2017 based on the Original Formula Rate, and any time period beyond, will not be known until the 2018 Annual Update is filed, and there could be further Final True Up Adjustments relating to the Original Formula Rate if it remains in effect past 2017.

Q. How can the "Cumulative Excess or Shortfall in Revenue with Interest" through the end of 2016 based on the Original Formula Rate be determined?

A. The Cumulative Excess or Shortfall in Revenue with Interest based on the Original Formula Rate through the end of 2016 is equal to the sum of two components: 1) The Cumulative Excess or Shortfall in Revenue with Interest through December of 2015, calculated using information from the True Up Adjustments of SCE's TO10 and TO11 Annual Update filings; and 2) the additional Excess or Shortfall in revenue associated with the 2016 year as determined in SCE's TO12 Annual Update.

Q. What is the Cumulative Excess or Shortfall in Revenue with Interest corresponding to December 2015 from SCE's TO11 Annual Update filing?

A. It is $89,464,304 undercollected. Because of the way the Original Formula Rate presents over and undercollection information, this amount must be determined by looking at both the TO10 and TO11 Annual Update True Up

Adjustments. The TO10 Annual Update contains the over/undercollection through the end of 2014, while the TO11 Annual Update contains the incremental over/undercollection during the 2015 year. So the December 2015 undercollection amount is calculated as the sum of the December 2015 balance from TO11 ($76,355,404 as shown on TO11 Annual Update, Schedule 3, Line 22, Column 9), as well as the December 2015 balance from the TO10 filing ($13,108,900 as shown on TO10 Annual Update, Schedule 3, Line 34, Column 9). This amount is developed in workpapers to Schedule 3 in Exhibit No. SCE-22.

This component of the Final True Up Adjustment for 2016 will be entered on Line 11, Column 4 of the populated Formula Rate Spreadsheet submitted with this filing (Exhibit SCE-4). Entering the $89,464,304 amount in this filing carries forward the cumulative over/undercollection history of the Original Formula Rate through the end of 2015.

Q. How can the second component, the "Additional Excess or Shortfall in Revenue Associated with the 2016 year as Determined in the TO12 Annual Update" of the Final True Up Adjustment for 2016 be reflected in the populated Formula Rate Spreadsheet?

A. The second component, the "Additional Excess or Shortfall in Revenue Associated with the 2016 year as Determined in the TO12 Annual Update" can be reflected in the populated Formula Rate Spreadsheet by making an adjustment to reflect the difference between the True Up TRRs calculated for 2016 by the Original Formula Rate Spreadsheet and by the proposed Formula Rate Spreadsheet (see proposed Formula Rate Protocols Section 6). Only the difference is entered because the populated proposed Formula Rate Spreadsheet True Up Adjustment already by default reflects the True Up TRR as calculated by the proposed Formula Rate. Including the difference as a One

Time Adjustment essentially converts the True Up TRR calculated pursuant to the proposed Formula Rate Spreadsheet reflected in this filing from being based on the proposed Formula Rate to being based on the Original Formula Rate, as it should be.

Q. What is the amount of the "additional Excess or Shortfall in revenue associated with the 2016 year as determined in the TO12 Annual Update" that should be entered as a One Time Adjustment?

A. The amount is negative $39,484,975, which is the difference in the True Up TRRs for the 2016 year calculated by the Original Formula Rate and this proposed Formula Rate as shown in Schedule 3, Line 23, Column 4. The determination of that amount, including interest through the end of 2016, is shown in my workpapers for Schedule 3 in Exhibit No. SCE-22.

Q. Will another One Time Adjustment to reflect the difference in True Up TRRs for the 2017 year be required to complete the Final True Up Adjustment for the Original Formula Rate?

A. Yes, in the Annual Update to be submitted by December 1, 2018 for the Rate Year 2019, the True Up TRR for the 2017 year will be known under both the Original Formula Rate and the proposed Formula Rate. The difference between the two will be entered in the True Up Adjustment for the Annual Update filed by December 1, 2018 in accordance with the requirement set forth in Section 6 of the proposed Formula Rate Protocols. Again, as with the adjustment for the 2016 True Up TRR, only the difference is entered because the populated proposed Formula Rate Spreadsheet already by default reflects the True Up TRR as calculated by the proposed Formula Rate. If the proposed Formula Rate is accepted by the Commission effective January 1, 2018 as requested by SCE, that action will complete the required actions for the Original Formula Rate Final True Up Adjustment. If the proposed Formula

Rate is suspended into part of 2018, another adjustment will be required in the Annual Update to be submitted by December 1, 2019 for Rate Year 2020.

VIII. INCLUSION OF RETURN ON EQUITY INCENTIVES IN THE PROPOSED FORMULA RATE

Q. Does SCE have any Commission-approved Return on Equity incentives for specific projects that are included in Rate Base?

A. Yes, as shown on Schedule 14, SCE received project-specific Return on Equity ("ROE") adders from the Commission for three projects: 1) Tehachapi Renewable Transmission Project (125 basis point ROE adder) Line 187; 2) Devers to Colorado River (100 basis point ROE adder), Line 190; and 3) the Rancho Vista substation (75 basis point ROE adder), Line 184. *See* Southern California Edison Co., 121 FERC ¶ 61,168 (2007). Schedule 14 summarizes the amounts of Incentive Plant on Lines 1-38, based on individual project information input on Lines 39-182.

Q. How does SCE's proposed Formula Rate reflect Return on Equity project incentive adders that the Commission has approved?

A. SCE's proposed Formula Rate quantifies the impact of Commission-approved ROE incentives by calculating cost components for the Prior Year TRR and for the True Up TRR which ensure that SCE recovers these ROE adder costs. These two components are:

1) The Prior Year Incentive Adder; and
2) The True Up Incentive Adder.

These two incentive adders are calculated in Schedule 15 of the proposed Formula Rate, and shown on Lines 14 and 20, respectively.

The Prior Year Incentive Adder represents the incremental impact on SCE's Prior Year TRR as a result of the above-mentioned ROE incentive adders. Similarly, the True Up Incentive Adder represents the incremental impact on SCE's True Up TRR as a result of these ROE incentive adders.

As previously discussed, it is the True Up TRR that defines the amount of transmission costs that SCE may recover through the operation of the proposed Formula Rate. Accordingly, it is only the True Up Incentive Adder that affects the amount of transmission costs that SCE will recover since it is a component of the True Up TRR. The Prior Year incentive adder is included in the Prior Year TRR for the purpose of correctly estimating the TRR costs that SCE will ultimately incur during the Rate Year, so that the magnitude of any True Up Adjustments may be minimized.

Q. Please describe how the Prior Year Incentive Adder is calculated.

A. The Prior Year Incentive Adder is calculated through the application of an Incremental Return on Equity Factor ("IREF") to the Net Plant of projects earning incentive adders. The IREF represents the incremental amount of revenue that SCE needs to receive in order to earn an extra 1.00% ROE, expressed per million dollars of Rate Base earning that extra 1.00% ROE adder.

The IREF is calculated on Line 3 of Schedule 15 according to the following formula:

IREF = CSCP * (1 / (1 – CTR)) * 1% * $1,000,000

Where:

CSCP = Common Stock Capital Percentage

CTR = Composite Tax Rate

Q. How is this formula derived so that it represents the incremental amount of revenue that SCE needs to receive in order to earn an extra 1.00% ROE, expressed per million dollars of Rate Base earning that extra 1.00% ROE adder?

A. The formula is constructed by first determining the incremental amount of equity that SCE would have as a result of $1 million of additional Rate Base. This is equal to the CSCP times $1 million. This is then multiplied by 1%, representing the hypothetical 1% increase in ROE, so that this product then represents the amount of after-tax revenue that SCE would need to retain in order to earn an incremental 1% ROE on the $1 million of Rate Base. Finally, a gross up factor is applied, representing the additional pre-tax revenue that SCE would have to receive in order to earn the required amount of after tax revenue. This gross up factor is equal to 1 / (1 – CTR). The gross up factor can be thought of as the percentage which, when multiplied by the amount of pre-tax income that remains after income taxes are paid (the 1 – CTR factor), equals one.

Q. Please explain how the IREF is used in determining the Prior Year Incentive Adder.

A. The Prior Year Incentive Adder for each individual project receiving an ROE adder is determined as the sum of the IREF times the number of million dollars of Net Plant associated with that project, and an additional multiplicative factor representing the ROE adder that the project is earning (for example, the multiplicative factor for Rancho Vista is 0.75, since it is only earning an ROE adder of 0.75%). The final amount of the Prior Year Incentive Adder is then the sum of the contribution of each project earning an ROE adder.

Q. Could you please provide an example of the calculation of the Prior Year Incentive Adder?

A. Assume the following values for inputs to the calculation:

IREF = $8,000

TRTP Net Plant = $500,000,000

Rancho Vista Net Plant = $200,000,000

Devers - Colorado River Net Plant = $400,000,000

TRTP ROE Adder = 1.25%

Rancho Vista ROE Adder = 0.75%

Devers - Colorado River ROE Adder = 1.00%

The Prior Year Incentive Adder would then be calculated as follows:

TRTP = 500 * $8,000 * 1.25 = $5,000,000

Rancho Vista = 200 * $8,000 * 0.75 = $1,200,000

DCR = 400 * $8,000 * 1.00 = $3,200,000

The total Prior Year Incentive Adder in this example is then the sum of the contribution of the three individual projects earning an ROE adder, or $9.4 million.

Q. Please describe how the True Up Incentive Adder is calculated.

A. The True Up Incentive Adder is calculated similarly to the Prior Year Incentive Adder, but using average plant balances over the Prior Year for the projects receiving the ROE adders. This True Up Incentive Adder is then included as a component of the True Up TRR.

Q. Does SCE have any Return on Equity incentives associated with being a member of the CAISO?

A. Yes, SCE has a 50 basis point ROE adder applicable to all Rate Base. Dr. Paul Hunt explains the basis of that 50 basis point ROE adder and how it is reflected in the Formula Rate Spreadsheet in his testimony, Exhibit No. SCE-17.

Q. Is SCE proposing to make any revisions to the calculation the Prior Year Incentive Adder or the True Up Incentive Adder on Schedule 15 compared to the Original Formula Rate?

A. No, the Schedule 15 calculations are unchanged.

Q. What are the calculated amounts of the Prior Year Incentive Adder and the True Up Incentive Adder for the proposed populated Formula Rate Spreadsheet?

A. The Prior Year Incentive Adder is $36,662,105 and the True Up Incentive Adder is $36,587,101. *See* Lines 14 and 20 of Schedule 15 of the populated Formula Rate Spreadsheet. Exhibit No. SCE-4.

IX. DETERMINATION OF SCE'S WHOLESALE BASE TRR

Q. Are there differences between SCE's Base TRR used for retail ratemaking purposes as compared to the Base TRR used for wholesale ratemaking purposes?

A. Yes, SCE's cost of service differs between retail and wholesale service. The Base TRR initially calculated in the proposed Formula Rate represents the retail cost of service, and certain adjustments must be made to properly calculate the Wholesale Base TRR. Accordingly, the proposed Formula Rate defines a "Wholesale Difference to the Base TRR" for use in determining the Wholesale Base TRR. The Wholesale Base TRR is equal to the Retail Base TRR less the Wholesale Difference to the Base TRR. The Wholesale Difference to the Base TRR is calculated in Schedule 25.

Q. What are sources of the difference between SCE's retail Base TRR and the Wholesale Base TRR?

A. SCE's Wholesale Base TRR differs from the Retail Base TRR due mainly to differences in ratemaking between retail and wholesale prior to the formation of the ISO in 1998. There are four ratemaking differences that are now being amortized over a remaining period of 27 years beginning in 1998, to be extinguished at the end of 2024:

1) The South Georgia Make Up Adjustment;
2) The Excess Deferred Taxes Adjustment;
3) The Deferred Taxes Account 282 Adjustment; and
4) The Accumulated Depreciation Difference.

Q. How do these four Rate Base factors affect the difference between the Wholesale and Retail Base TRR?

A. Each of these four Rate Base-related adjustments affects the difference between the Wholesale and Retail Base TRR through two paths: 1) a Rate Base effect; and 2) an Expense (or amortization) effect. The Rate Base effect is due to the remaining unamortized difference in the balance between retail and wholesale ratemaking that directly affects the Wholesale Rate Base relative to the Retail Rate Base. The Expense effect is due to the annual amortization of the balances.

Q. What is the South Georgia Make Up Adjustment?

A. Mr. Lopez discusses the South Georgia Make Up Adjustment in his testimony, Exhibit No. SCE-11. As Mr. Lopez states, the South Georgia Make Up Adjustment normalizes tax benefits previously flowed through to End Use Customers. The South Georgia Make Up Adjustment currently contributes about a $35 million reduction to the Wholesale Rate Base relative to the Retail Rate Base (Line 8, Column 1 of Schedule 25). On the expense side, there is an annual amortization of $2.5 million that must be grossed up for Income Taxes, so that it serves to reduce the Wholesale Base TRR by about $4.2 million (Line 33 of Schedule 25).

Q. What is the Excess Deferred Taxes Adjustment?

A. Mr. Lopez discusses the Excess Deferred Taxes Adjustment in his testimony, Exhibit SCE-11. It is currently a reduction in Wholesale Rate Base relative to Retail of about $625,000 (Line 9, Column 1 of Schedule 25), and accounts for an annual expense reduction of about $73,000 (Line 34 of Schedule 25).

Q. What is the Deferred Taxes – Account 282 Adjustment?

A. Mr. Lopez discusses the Deferred Taxes – Account 282 Adjustment in his testimony, Exhibit SCE-11. It is currently a reduction in Wholesale Rate Base relative to Retail of about $7.4 million (Line 10, Column 1 of Schedule 25), and accounts for an annual expense reduction of about $511,000 (Line 35 of Schedule 25).

Q. What is the Accumulated Depreciation Difference?

A. Mr. Gunn explains why the Accumulated Depreciation Difference exists and how it is determined in his testimony, Exhibit SCE-7. The Accumulated Depreciation Difference is currently about $31.6 million (Line 7, Column 1 of Schedule 25), serving to increase Wholesale Rate Base relative to Retail Rate Base.

The annual expense impact is $2.176 million (Line 32 of Schedule 25), increasing the Wholesale Base TRR relative to the Retail Base TRR.

Q. Are there any expense items that should not be included in the Wholesale Base TRR that are in the Retail Base TRR?

A. Yes, there are two expense items that affect are included in the Retail Base TRR that should not be included in the Wholesale Base TRR: 1) Uncollectibles Expense (about 0.24%) is not applied to the Wholesale Base TRR as it is to the

Retail Base TRR; and 2) EPRI and EEI dues are excluded from the Wholesale TRR. Both of these expense items are considered in developing the Wholesale Adjustment to the Base TRR as calculated on Schedule 25 of the proposed Formula Rate Spreadsheet. An "EPRI and EEI Dues Exclusion" is calculated on Lines 25-31, and Uncollectibles Expense is excluded on Lines 41-42. It is appropriate to exclude EPRI and EEI Dues from wholesale rates since wholesale customers are responsible for their own EPRI and EEI Dues. Additionally, it is appropriate to exclude Uncollectibles expenses from the Wholesale TRR since uncollectibles expense only relates to retail revenue collection.

Q. Does the proposed Formula Rate provide for the Wholesale Difference to the Base TRR to change over time as the amortization of the above four items reduces the difference in Rate Base between Wholesale and Retail?

A. Yes. As the differences in these rate base items change over time (*i.e.*, from one Prior Year to the next Prior Year) according to known amortization rates, the proposed Formula Rate will recalculate the Wholesale Difference to the Base TRR. This is accomplished in the proposed Formula Rate by recalculating the Wholesale Rate Base Difference given the amortizations of each component of the difference as a function of the value of the Prior Year. Schedule 25 shows this calculation on Lines 12-15.

Q. Is SCE proposing any changes to Schedule 25 compared to the Original Formula Rate?

A. Yes, SCE is proposing to add the capability to exclude any other expenses that may be determined to not be appropriate for recovery from Wholesale customers. This is accomplished in the Formula Rate Spreadsheet by the addition of Line 37 "Additional Expense Difference." SCE is not aware of any instances since the inception of the Original Formula Rate in 2012 that there were any such differences, but is proposing to add this capability in case an instance arises in the future. The 2016 input value for Line 37 of Schedule 25 is $0.

Q. What is the amount of the "Wholesale Difference to the Base TRR" for the 2016 Prior Year TRR?

A. It is negative $6,395,449, as shown on Schedule 25, Line 45. This amount carries over to the calculation of the Wholesale Base TRR on Schedule 1, Line 88.

Q. What is the purpose of Schedule 29 "Wholesale TRRs" of the Formula Rate Spreadsheet?

A. Schedule 30 calculates High and Low Voltage components of SCE's total Wholesale Base TRR from Schedule 25. SCE is required to provide the High and Low Voltage components of the Wholesale Base TRR to the CAISO for its use in calculating its Transmission Access Charges. SCE is not proposing to revise Schedule 29 in this proposed Formula Rate.

X. WHOLESALE TRANSMISSION RATES

Q. What wholesale transmission rates are currently stated in SCE's Transmission Owner Tariff and calculated in the proposed Formula Rate?

A. SCE's Transmission Owner Tariff ("TO Tariff") currently sets forth six wholesale transmission rates, as follows:

1) Low Voltage Access Charge
2) High Voltage Wheeling Access Charge
3) Low Voltage Wheeling Access Charge
4) High Voltage Utility Specific Rate
5) High Voltage Existing Contracts Access Charge
6) Low Voltage Existing Contracts Access Charge

These rates are set forth in Appendix II of SCE's TO Tariff, and refer to SCE's Annual Update Formula Rate Spreadsheet posted on SCE's website for the actual rate in effect at any point in time (with the exception of the High Voltage Wheeling Access Charge, for which Appendix II states “See ISO Tariff” since that rate is actually calculated and assessed to CAISO Wheeling customers by the CAISO. SCE’s Formula Rate Spreadsheet calculates these rates in Schedule 30.

Q. Is SCE proposing to remove any wholesale transmission rates from the Formula Rate Spreadsheet tariff and TO Tariff Appendix II?

A. Yes, SCE has reviewed the wholesale rates that are currently set forth in SCE’s TO Tariff and calculated pursuant to SCE’s Formula Rate Spreadsheet tariff Schedule 30, and determined that the Low Voltage Existing Contracts Access Charge (“LVECAC”) is not currently utilized and will not be required in the future, and accordingly can be removed from SCE’s TO Tariff. The LVECAC is applied to Existing Contract customers of SCE when their service uses SCE’s Low Voltage facilities. SCE no longer has any Existing Contracts that use SCE’s Low Voltage facilities, and will not in the future since new Existing Contracts cannot be created since the formation of the CAISO in 1998.

Q. Is SCE proposing to remove any of these Wholesale rates from its TO Tariff or Formula Rate Spreadsheet tariff?

A. Yes. SCE is proposing to remove the LVECAC from both the Appendix II of the TO tariff and its associated calculation in Schedule 30 of the Formula Rate Spreadsheet tariff.

Q. Is SCE proposing any additional changes to Appendix II of the TO Tariff or Schedule 30 of the Formula Rate Spreadsheet tariff relating to Existing Contracts?

A. Yes. SCE is proposing to revise Appendix II to the TO Tariff to clarify that both the High Voltage Wheeling Access Charge and the Low Voltage Wheeling Access Charge are assessed by the CAISO and stated in the CAISO

Tariff. Additionally, SCE is proposing to remove the calculation of the Low Voltage Wheeling Access Charge from the Formula Rate Spreadsheet tariff Schedule 30. These changes will clarify that it is the CAISO that assesses these two Wheeling Access Charges, not SCE.

Q. Does the calculation of the Wholesale Rates performed on Schedule 30 rely on any information besides the Wholesale TRRs from Schedule 29?

A. Yes. The calculation of the Wholesale rates performed on Schedule 30 uses "Gross Load," which is the sum of SCE's forecast MWh retail sales measured at the CAISO grid level, and SCE's forecast MWh pump load for the Rate Year. Additionally, some rates rely on "Forecast 12-CP Retail Load." The calculation of Gross Load and Forecast 12-CP Retail Load is shown on Schedule 32, Lines 3 and 4, respectively. SCE is not proposing to revise Schedule 32 in this proposed Formula Rate.

XI. THE FORMULA RATE PROTOCOLS

Q. What are the Formula Rate Protocols?

A. The Formula Rate Protocols describe process-related items and requirements associated with the ongoing implementation of SCE's proposed Formula Rate. The Formula Rate Protocols are Attachment 1 to Appendix IX of SCE's Transmission Owner Tariff ("TO Tariff"). The Formula Rate Protocols consist of 12 Sections, as follows:

1) Introduction
2) Term of the Formula Rate
3) Procedures for Updating the Base TRR
4) The Annual True Up Adjustment and the Final True Up Adjustment
5) The Incremental Forecast Period TRR
6) Transition of the Original Formula Rate to the Formula Rate
7) Depreciation Rates
8) Revisions to Certain Formula Rate Provisions
9) Determination of Amount of Transmission Plant-ISO and Distribution Plant-ISO

10) Determination of Amount of ISO Operations and Maintenance Expense
11) Reservation of Rights
12) Use of Information

Q. Could you please describe Section 1 of the Formula Rate Protocols (Introduction)?

A. The Introduction of the Formula Rate Protocols explains some general details regarding the Formula Rate, including: 1) that the Base TRR will be calculated pursuant to the Formula Rate Spreadsheet; 2) that SCE will update its Base TRR annually; 3) the components of the Base TRR; and 4) the calculation of the Wholesale Base TRR.

Q. Could you please describe Section 2 of the Formula Rate Protocols (Term of the Formula Rate)?

A. Section 2 of the Formula Rate Protocols describes the term of the proposed Formula Rate. SCE is proposing that the proposed Formula Rate become effective January 1, 2018 without any termination date, as set forth in Section 2. Additionally, Section 2 specifies that the proposed Formula Rate will remain in effect until any successor rate mechanism is made effective by the Commission.

Q. Could you please describe Section 3 of the Formula Rate Protocols (Procedures for Updating the Base TRR)?

A. Section 3 of the Formula Rate Protocols describes the procedures for updating the proposed Formula Rate, including: 1) SCE will post a Draft Annual Update on its website by June 15 of each year; and 2) SCE will file an Annual Update of its Base TRR and associated retail and wholesale rates by December 1 of each year based on the Formula Rate Spreadsheet. Section 3 also sets forth several requirements for information to be included in Draft Annual Updates and Annual Updates, and describes the requirements during the time between the posting of the Draft Annual Update and the filing of the Annual Update, including the information request requirements.

Section 3 also describes the process that SCE must follow if it determines that a previously-filed Annual Update filing contained an error in the determination of the True Up TRR in that filing. Briefly, SCE is required to determine the impact of that error by rerunning the proposed Formula Rate Spreadsheet with the correct inputs, and comparing the obtained True Up TRR with the originally-filed True Up TRR. If the error resulted in a positive change in the True Up TRR of over $1 million, then SCE must submit an Amended Annual Update filing to the Commission showing the derivation of the change in the True Up TRR; otherwise, if it is less than $1 million, SCE is not required to submit an Amended Annual Update to the Commission. SCE must also remedy the error by including as a "One Time Adjustment" the change in the True Up TRR (including interest) in the current year Annual Update.

Q. Is SCE proposing any changes to the conditions under which SCE must determine the impact of an error in a previous Annual Update relative to the Original Formula Rate protocols?

A. Yes. SCE is proposing to limit SCE's obligation to calculate and include the impact of any error in a previous Annual Update to only apply to Annual Updates with a Prior Year two years or less before the current Annual Update Prior Year (See section 3.d.8 of the proposed Formula Rate protocols). This would provide a three-year period for which errors must be corrected if discovered (the current Prior Year plus two additional years). This revision will be beneficial in reducing administrative effort by both SCE and customers, while still providing a reasonable period for both SCE and customers to discover any errors in previous Annual Updates.

Q. Are you aware of any similar limitations on the requirement to recalculate errors in any Commission-jurisdictional tariffs?

A. Yes. The CAISO has a similar limitation on requirement to recalculate settlements in its Tariff. Section 11.29.8.4.7 of the CAISO Tariff limits the obligation of the CAISO to recalculate settlements to a three-year period, except as ordered by the CAISO Governing Board or pursuant to a Commission Order.

Q. Could you please describe Section 4 of the Protocols (The Annual True Up Adjustment and the Final True Up Adjustment)?

A. Section 4 of the Protocols describes the Annual True Up Adjustment and the Final True Up Adjustment. The purpose of these adjustments is to ensure that over the life of the proposed Formula Rate, SCE will recover its actual costs of service, as defined by the True Up TRRs for each year that the proposed Formula Rate is in effect. During each Annual Update, SCE will compare on a monthly basis for the Prior Year the retail transmission revenues to the True Up TRR. The monthly differences between the two will determined, and the cumulative difference at the end of the Prior Year, including interest, will be called the "Shortfall or Excess Revenue in the Prior Year." That amount of "Shortfall or Excess Revenue in the Prior Year" will be included as the beginning balance in the next Annual Update, ensuring that over multiple Annual Updates, the True Up Adjustment mechanism will keep track of SCE's cumulative over or undercollection in revenues. Additionally, in the event that this proposed Formula Rate does terminate at some point, Section 4 describes how a Final True Up Adjustment is to be calculated and collected or returned through SCE's successor Base TRR mechanism.

Q. Could you please describe Section 5 of the Protocols (The Incremental Forecast Period TRR)?

A. Section 5 of the Protocols is a brief summary of the Incremental Forecast Period TRR.

Q. Could you please describe Section 6 of the Protocols (Transition of the Original Formula Rate into the Formula Rate)?

A. Section 6 of the Protocols describes how the ending over or under collections of revenue from the six-year term of the Original Formula Rate are to be reflected in the proposed Formula Rate as One Time Adjustments, ensuring that SCE's actual transmission costs (as determined by the six True Up TRRs) over that term are ultimately recovered, either through revenue during the six-year term, or as One Time Adjustments carried forward for recovery through this proposed Formula Rate.

Q. Could you please describe Section 7 of the Protocols (Depreciation Rates)?

A. Section 7 of the Formula Rate Protocols is a brief statement that the depreciation rates used in the proposed Formula Rate are stated values in the Formula Rate Spreadsheet.

Q. Could you please describe Section 8 of the Formula Rate Protocols (Revisions to Certain Formula Rate Provisions)?

A. Section 8 describes the process for making revisions to the proposed Formula Rate, including some revisions that may be made pursuant to "single-issue" filings whereby the only issue that is to be reviewed in the proceeding is that one issue. The Protocols include descriptions of five aspects of the proposed Formula Rate for which SCE is required to propose revisions to the proposed Formula Rate, and the circumstances under which SCE must make such a single-issue filing. These five aspects with single-issue filing rights are each ministerial or implementation filings, and should not subject the proposed

Formula Rate to dispute, and therefore are appropriate for single-issue treatment. The five aspects for which there are single-issue filing requirements are:

1) The requirement to make conforming revisions to references in the Formula Rate to FERC Form 1 page, line, and column locations when these locations change in FERC Form 1.

2) The requirement to make revisions to the Authorized PBOPs Expense Amount on an annual basis.

3) The requirement to make revisions to the Gross Revenue Sharing Mechanism component of the Revenue Credits calculation in the event that the California Public Utilities Commission ("CPUC") makes revisions to that mechanism

4) The requirement to make a revision to the Formula Rate calculation of retail transmission rates to conform to CPUC rate design in the event that the CPUC revises its retail rate design.

5) The requirement to make a revision to General, Intangible, and Distribution depreciation rates stated in the Formula Rate in the event that the CPUC revises its approved General, Intangible, and Distribution depreciation rates.

Q. Is SCE proposing any significant revisions to Section 8 of the protocols?

A. Yes. SCE is proposing to revise the method of determining whether a filing to revise the Authorized PBOPs Expense Amount is required. SCE's proposal is to make a filing each year by April 1, rather than utilize the previous biennial mechanism that assessed whether a new filing should be made. SCE believes this annual filing requirement will actually result in less administrative effort, while at the same time yielding reasonable Authorized PBOPs Expense Amounts.

Additionally, SCE is proposing to revise the timeline for making filings to revise the stated values of General, Intangible, and Distribution Depreciation rates, as well as any filing to conform the Gross Revenue Sharing Mechanism component of Revenue Credits, in accordance with a CPUC Order. The proposed timeline is to make such filings between January 1 and March 1 in the year following the implementation of any such changes. SCE believes that this revised filing timeline requirement will assure that any such changes can be timely made.

Q. Could you please describe Section 9 of the Protocols (Determination of the Amount of Transmission Plant – ISO and Distribution Plant - ISO)?

A. Section 9 describes the process by which the amount of plant under the ISO's Operational Control, and thus subject to cost recovery through this proposed Formula Rate, is determined from the total dollar amount of plant booked as Transmission or Distribution.

Q. Could you please describe Section 10 of the Protocols (Determination of the Amount of ISO Operation and Maintenance Expense)?

A. Section 10 describes the determination of the amount of total Operation and Maintenance ("O&M") Expense that relates to the facilities under the ISO's Operational Control, and thus should be recovered through the proposed Formula Rate.

Q. Could you please describe Section 11 of the Protocols (Reservation of Rights)?

A. Section 11 is a statement of specific legal rights that SCE or other parties have with respect to the proposed Formula Rate, including that: 1) Nothing in the Formula Rate Protocols limits the rights of intervenors in Annual Update proceedings to seek relief under the Federal Power Act ("FPA"); 2) Nothing in the Formula Rate Protocols limits SCE's rights to file pursuant to Section 205 of the FPA to revise or cancel the Formula Rate; and 3) Any party filing under either Section 205 or 206 of the FPA bears the standard burdens associated with such a filing.

Q. Could you please describe Section 12 of the Formula Rate Protocols (Use of Information)?

A. Section 12 describes under what conditions information produced pursuant to the Protocols may be used in other proceedings.

Q. Has SCE eliminated any Protocol Sections in the proposed Formula Rate Protocols?

A. Yes. SCE has eliminated previous Section 12 "Periodic Informational Submittals" from the Original Formula Rate. Previous Section 12 included three information submissions to the CPUC: 1) Quarterly Tracking Reports; 2) Transfer of Control Informational Submission; and 3) Transmission Capital Review. SCE did not include these informational submittals in SCE's initial filing of the Original Formula Rate, but agreed to include these informational submittals as part of the settlement of the case. SCE agreed to these provisions in the settlement of the Original Formula Rate. However, SCE has determined that there is no Commission requirement that would require such informational submittals, and accordingly is proposing to delete previous Section 12 of the Formula Rate Protocols.

Q. Is SCE proposing any other changes to the Formula Protocols compared to the Original Formula Rate protocols?

A. Yes. In Exhibit No. SCE-6 I have summarized all proposed changes relative to the Original Formula Rate Protocols currently in effect, as stated in Appendix IX, Attachment 2, to SCE's TO Tariff.

XII. THE FORMULA RATE SPREADSHEET

Q. What is the Formula Rate Spreadsheet?

A. The Formula Rate Spreadsheet tariff sets forth the calculations to implement the calculation of SCE's Base TRR and associated retail and wholesale rates as I have described above. Attachment 2 to Appendix IX of SCE's TO Tariff shows these calculations in tariff format. In each Annual Update, SCE will implement the tariff calculation directions through the use of an Excel file populated with cost inputs.

Q. Please describe the format of the Formula Rate Spreadsheet.

A. The Formula Rate Spreadsheet consists of thirty-four individual schedules that together calculate SCE's Base TRR and associated retail and wholesale transmission rates in an Annual Update based on cost inputs and certain stated values. The first schedule, 1-Base TRR, calculates the total retail and wholesale Base TRRs, while the remaining schedules primarily determine amounts of various costs used in the 1-Base TRR schedule. Every numeric value on a line of the Formula Rate Spreadsheet used in the calculations is either: 1) a cost input; 2) a stated value; or 3) a calculated value (final or intermediate).

Q. Please describe how an input is represented in the Formula Rate Spreadsheet.

A. An input, which is generally a cost amount, is represented by a yellow-shaded location in the spreadsheet, with an associated unambiguous description of the amount to be entered in that location. In an Annual Update, SCE will follow the descriptions for each yellow-shaded input and extract the required information from FERC Form 1 or SCE's records and populate the Formula Rate Spreadsheet. Once all of the yellow-shaded inputs are populated with the appropriate inputs, the spreadsheet will calculate the ultimate outputs (primarily the Base TRR and associated retail and wholesale transmission rates).

Q. What is a stated value in the Formula Rate Spreadsheet?

A. A stated value is an amount (either dollar costs or percentages that are used in expense calculations) that is hard-wired into the Formula Rate Spreadsheet, and accordingly is not yellow-shaded as inputs are. Since a stated value is not an input, but rather an fixed component of the Formula Rate, it is not subject to revision except pursuant to FERC approval of either a Section 205 or 206 filing. Examples of stated values are Return on Equity (Schedule 1, Line 50) depreciation rates (Schedule 18), and the Authorized PBOPs Expense Amount (Schedule 20, Note 3, Line "a").

Q. Please list each of the schedules in Attachment 1, including a description of its purpose in the proposed Formula Rate, and the witness that will be sponsoring it in this filing.

A. The schedules are listed below:

Schedule 1 (BaseTRR): This schedule calculates the values for the retail and wholesale Base TRRs, in many cases utilizing information from the remaining schedules regarding the amount of various components of the Base TRR. I am sponsoring most of Schedule 1; however, Mr. David Gunn sponsors the Cash Working Capital calculation on (Line 7) in Exhibit No. SCE-7, Mr. Alfred Lopez sponsors Other Taxes and Income Taxes (Lines 19-36 and 57-65) in Exhibit No. SCE-11, and Dr. Paul Hunt sponsors Return and Capitalization (Lines 37-56) in Exhibit No. SCE-17.

Schedule 2 (IFPTRR): This schedule calculates the Incremental Forecast Period TRR. This Schedule is discussed in Section IV of my testimony.

Schedule 3 (TrueUpAdjust): This schedule calculates the True Up Adjustment. This Schedule is discussed in Section VI of my testimony.

Schedule 4 (TrueUpTRR): This Schedule calculates the True Up TRR. It is discussed in Section V of my testimony.

Schedule 5 (ROR): This schedule calculates the capital structure and associated capital costs. It is composed of four subpart schedules: ROR-1 (Calculation of Components of Cost of Capital Rate); ROR-2 (Calculation of 13-Month Average Capitalization Balances); ROR-3 (Cost of Debt); and ROR-4 (Cost of Preferred Stock). This Schedule is discussed in Dr. Hunt's testimony, Exhibit SCE-17.

Schedule 6 (PlantInService): This schedule calculates the amount of In-Service Plant, composed of Transmission Plant – ISO, Distribution Plant – ISO, General Plant, and Intangible Plant. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 7 (PlantStudy): This schedule summarizes the results of the Plant Study, showing the amount of Transmission Plant – ISO and Distribution Plant – ISO by account. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9.

Schedule 8 (AccDep): This schedule calculates Accumulated Depreciation. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 9 (ADIT): This schedule calculates Accumulated Deferred Income Taxes. This Schedule is discussed in Mr. Lopez's testimony, Exhibit SCE-11.

Schedule 10 (CWIP): This schedule presents CWIP balances in the Prior Year for each project that SCE has Commission approval to include in Rate Base, and presents forecast amounts of CWIP for each project through the end of the Forecast Period, and calculates the Incremental CWIP amounts for use in calculating the Incremental Forecast Period TRR. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 11 (PHFU): This schedule calculates Plant Held for Future Use, as well as any "Gain or Loss on Transmission Plant Held for Future Use – Land." This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 12 (AbandonedPlant): This schedule calculates Abandoned Plant balances and Abandoned Plant Amortization Expense. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

Schedule 13 (WorkCap): This schedule calculates the Materials and Supplies and Prepayments components of Working Capital. This Schedule is discussed Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 14 (IncentivePlant): This schedule summarizes Incentive Plant balances for each project for which SCE has Commission approval to include in Rate Base, or that earns an ROE adder (or both). This Schedule is discussed in Section VIII of my testimony (for Lines 1-38, summary of Amounts of Incentive Plant), and Mr. Gunn's testimony, Exhibit SCE-7, for the amounts of Prior Year Net Plant in Service (Lines 39-182).

Schedule 15 (IncentiveAdder): This schedule calculates the ROE Incentive Adders to include in both the Prior Year TRR and the True Up TRR. This Schedule is discussed in Section VIII of my testimony.

Schedule 16 (PlantAdditions): This schedule presents SCE's Forecast Plant Additions for in-service plant. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 17 (Depreciation): This schedule calculates Depreciation Expense. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

Schedule 18 (DepRates): This schedule presents the depreciation rates that the Formula Rate Spreadsheet uses to calculate depreciation expense. This Schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

<u>Schedule 19 (OandM):</u> This schedule calculates Operations and Maintenance Expense. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9, as well as Mr. Allstun's testimony, Exhibit No. SCE-10.

<u>Schedule 20 (AandG):</u> This schedule calculates Administrative and General Expense. This Schedule is discussed in Mr. Mindess' testimony Exhibit SCE-12.

<u>Schedule 21 (RevenueCredits):</u> This schedule calculates the Revenue Credits, including credits pursuant to the CPUC-authorized Gross Revenue Sharing Mechanism ("GRSM"). This Schedule is discussed in Ms. Kim's testimony, Exhibit SCE-13.

<u>Schedule 22 (NUCs):</u> This schedule calculates Network Upgrade Credits and Interest on Network Upgrade Credits. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

<u>Schedule 23 (RegAssets):</u> This schedule calculates Regulatory Assets/Liabilities and Regulatory Debits. This Schedule is discussed in Mr. Ocegueda's testimony, Exhibit SCE-15.

<u>Schedule 24 (CWIPTRR):</u> This schedule calculates, for informational purposes only, the contribution of CWIP in Rate Base to the Prior Year TRR, the Incremental Forecast Period TRR, the True Up TRR, and the Retail Base TRR. This Schedule is discussed in Section III of my testimony.

<u>Schedule 25 (WholesaleDifference):</u> This schedule calculates the Wholesale Difference to the Base TRR. This Schedule is discussed in Section IX of my testimony.

<u>Schedule 26 (TaxRates):</u> This schedule calculates the tax rates used in the Formula Rate Spreadsheet, including the Federal Income Tax Rate and the Composite State Income Tax Rate. This Schedule is discussed in Mr. Lopez's testimony, Exhibit SCE-11.

Schedule 27 (Allocators): This schedule calculates the Transmission Wages and Salaries Allocation factor and the Transmission Plant Allocation Factor, as well as certain allocation factors that are used in the calculation of ISO O&M Expense. Mr. Ocegueda's discusses the Transmission Wages and Salaries Allocation factor and the Transmission Plant Allocation Factor in his testimony, Exhibit No. SCE-15. Mr. Moon discusses the allocation factors used in the calculation of ISO O&M Expense in his testimony, Exhibit SCE-9.

Schedule 28 (FFU): This schedule calculates the Franchise Fee and Uncollectibles Factors used in the Formula Rate Spreadsheet to calculate Franchise Fees Expense and Uncollectibles Expense. This Schedule is discussed in Mr. Mindess' testimony, Exhibit SCE-12.

Schedule 29 (WholesaleTRRs): This schedule calculates the Wholesale TRRs used in the determination of the Wholesale Transmission Rates. This Schedule is discussed in Section IX of my testimony.

Schedule 30 (WholesaleRates): This schedule calculates SCE's wholesale transmission rates. This Schedule is discussed in Section X of my testimony.

Schedule 31 (HVLV): This schedule calculates the High and Low Voltage Gross Plant percentages. This Schedule is discussed in Mr. Moon's testimony, Exhibit SCE-9.

Schedule 32 (GrossLoad): This schedule presents the forecast load used in calculating retail and wholesale transmission rates. This Schedule is discussed in Section X of my testimony.

Schedule 33 (RetailRates): This schedule calculates retail transmission rates. This Schedule is discussed in Mr. Thomas' testimony, Exhibit SCE-16.

Schedule 34 (UnfundedReserves): This schedule calculates the Unfunded

Reserves component of Rate Base. This schedule is discussed in Mr. Gunn's testimony, Exhibit SCE-7.

XIII. SCE'S PROPOSED RETAIL AND WHOLESALE BASE TRRS AND RATES EFFECTIVE JANUARY 1, 2018

Q. What is SCE's proposed retail Base TRR effective January 1, 2018?

A. It is $1,169,306,623, as shown on Line 86 of Schedule 1 of the Formula Rate Spreadsheet (Exhibit SCE-4).

Q. What is SCE's proposed Wholesale Base TRR effective January 1, 2018?

A. It is $1,162,911,173, as shown on Line 89 of Schedule 1 of the Formula Rate Spreadsheet (Exhibit SCE-4).

Q. What are SCE's proposed Base retail transmission rates effective January 1, 2018?

A. SCE's proposed Base retail transmission rates are as developed on Schedule 33 of the populated Formula Rate Spreadsheet, Exhibit SCE-4.

Q. What are SCE's proposed Base Wholesale transmission rates effective January 1, 2018?

A. SCE's proposed Base Wholesale transmission rates are as developed on Schedule 30 of the populated Formula Rate Spreadsheet, Exhibit SCE-4. The proposed rates are as follows:

High Voltage Existing Contracts Access Charge: $6.16 per kW-month
High voltage Utility Specific Rate: $0.0114279 per kWh
Low Voltage Access Charge: $0.00031 per kWh

Q. Does this complete your testimony?

A. Yes.

<u>AFFIDAVIT of AUTHENTICATION</u>

State of California)

) ss

County of Los Angeles)

Berton J. Hansen, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Berton J. Hansen

Berton J. Hansen

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 25th day of October, 2017 by

Berton J. Hansen, proved to me on the basis of

satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-4

EXHIBIT TO THE TESTIMONY OF MR. BERTON J. HANSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Exhibit SCE-4

Proposed Formula Rate Spreadsheet for 2018 Rate Year

Attachment 2 to Appendix IX

Formula Rate Spreadsheet

Table of Contents

Overview of SCE Retail Base TRR

SCE's retail Base Transmission Revenue Requirement is the sum of the following components:

TRR Component	Amount
Prior Year TRR	$1,099,599,089
Incremental Forecast Period TRR	$109,324,746
True-Up Adjustment	-$39,617,212
Cost Adjustment	$0
Base TRR (retail)	$1,169,306,623

These components represent the following costs that SCE incurs:

1) The Prior Year TRR component is the TRR associated with the Prior Year (most recent calendar year). The Prior Year TRR is calculated using End-of-Year Rate Base values, as set forth in the "1-BaseTRR" Worksheet.

2) The Incremental Forecast Period TRR is the component of Base TRR associated with forecast additions to in-service plant or CWIP, as set forth in the "2-IFPTRR" Worksheet.

3) The True Up Adjustment is a component of the Base TRR that reflects the difference between projected and actual costs, as set forth in the "3-TrueUpAdjust" Worksheet.

4) The Cost Adjustment component may be included as provided in the Tariff protocols.

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2016 Value
RATE BASE				
1	ISO Transmission Plant		6-PlantInService, Line 19	$8,276,570,295
2	General Plant + Electric Miscellaneous Intangible Plant		6-PlantInService, Line 27	$279,277,011
3	Transmission Plant Held for Future Use		11-PHFU, Line 8	$9,942,155
4	Abandoned Plant		12-AbandonedPlant, Line 3	$0
	Working Capital amounts			
5	Materials and Supplies		13-WorkCap, Line 16	$14,660,302
6	Prepayments		13-WorkCap, Line 36	$6,126,106
7	Cash Working Capital		(Line 66 + Line 67) / 8	$16,684,622
8	Working Capital		Line 5 + Line 6 + Line 7	$37,471,030
	Accumulated Depreciation Reserve Balances			
9	Transmission Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 13, Col. 12	-$1,467,790,558
10	Distribution Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 16, Col. 5	$0
11	General + Intangible Plant Depreciation Reserve	Negative amount	8-AccDep, Line 26	-$118,208,640
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	-$1,585,999,198
13	Accumulated Deferred Income Taxes	Negative amount	9-ADIT, Line 4, Col. 2	-$1,550,608,605
14	CWIP Plant		14-IncentivePlant, L 12, Col 1	$115,749,706
15	Other Regulatory Assets/Liabilities		23-RegAssets, Line 14	$0
16	Unfunded Reserves		34-UnfundedReserves, Line 6	-$11,279,549
17	Network Upgrade Credits	Negative amount	22-NUCs, Line 4	-$119,779,556
18	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L16 + L17	$5,451,343,289
OTHER TAXES				
19	Sub-Total Local Taxes	FF1 263.2, Row 39, Column i	FF1 263 or 263.x (see note to left)	$280,920,490
20	Transmission Plant Allocation Factor		27-Allocators, Line 22	19.3143%
21	Property Taxes		Line 19 * Line 20	$54,257,710
22	Payroll Taxes Expense			
23	FICA		Line 24 + Line 25+ Line 26	$106,138,253
24	Fed Ins Cont Amt -- Current	FF1 263, Row 6, Column i	FF1 263 or 263.x (see note to left)	$106,128,138
25	FICA/OASDI Emp Incntv.	FF1 263, Row 8, Column i	FF1 263 or 263.x (see note to left)	$318
26	FICA/HIT Emp Incntv.	FF1 263, Row 9, Column i	FF1 263 or 263.x (see note to left)	$9,797
27	CA SUI Current	FF1 263, Row 24, Column i	FF1 263 or 263.x (see note to left)	$6,103,726
28	Fed Unemp Tax Act- Current	FF1 263, Row 10, Column i	FF1 263 or 263.x (see note to left)	$2,343,205
29	CADI Vol Plan Assess	FF1 263.1, Row 40, Column i	FF1 263 or 263.x (see note to left)	$1,557,248
30	SF Pyrl Exp Tx - SCE	FF1 263.1, Row 38, Column i	FF1 263 or 263.x (see note to left)	$21,880
31	Total Electric Payroll Tax Expense		Line 23 + (Line 27 to Line 30)	$116,164,312
32	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 16	$46,233,396
33	Remaining Electric Payroll Tax Expense to Allocate		Line 31 - Line 32	$69,930,916
34	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9	6.1650%
35	Payroll Taxes Expense		Line 33 * Line 34	$4,311,242
36	Other Taxes	Note 1	Line 21 + Line 35	$58,568,952

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**2016 Value**
	RETURN AND CAPITALIZATION CALCULATIONS			
	Debt			
37	Long Term Debt Amount		5-ROR-1, Line 12	$9,523,029,143
38	Cost of Long Term Debt		Line 37 * Line 39	$472,494,563
39	Long Term Debt Cost Percentage		5-ROR-3, Line 10	4.9616%
	Preferred Stock			
40	Preferred Stock Amount		5-ROR-1, Line 16	$2,152,785,189
41	Cost of Preferred Stock		Line 40 * Line 42	$124,915,908
42	Preferred Stock Cost Percentage		5-ROR-4, Line 9	5.8025%
	Equity			
43	Common Stock Equity Amount		5-ROR-1, Line 22	$11,956,142,581
44	Total Capital		Line 37 + Line 40 + Line 43	$23,631,956,913
	Capital Percentages			
45	Long Term Debt Capital Percentage		Line 37 / Line 44	40.2973%
46	Preferred Stock Capital Percentage		Line 40 / Line 44	9.1096%
47	Common Stock Capital Percentage		Line 43 / Line 44	50.5931%
			Line 45 + Line 46+ Line 47	100.0000%
	Annual Cost of Capital Components			
48	Long Term Debt Cost Percentage		Line 39	4.9616%
49	Preferred Stock Cost Percentage		Line 42	5.8025%
50	Return on Common Equity	Note 2	SCE Return on Equity	10.80%
	Calculation of Cost of Capital Rate			
51	Weighted Cost of Long Term Debt		Line 39 * Line 45	1.9994%
52	Weighted Cost of Preferred Stock		Line 42 * Line 46	0.5286%
53	Weighted Cost of Common Stock		Line 47 * Line 50	5.4641%
54	Cost of Capital Rate		Line 51 + Line 52 + Line 53	7.9920%
55	Equity Rate of Return Including Common and Preferred Stock	Used for Tax calculation	Line 52 + Line 53	5.9926%
56	Return on Capital: Rate Base times Cost of Capital Rate		Line 18 * Line 54	$435,673,172
	INCOME TAXES			
57	Federal Income Tax Rate		26-Tax Rates, Line 1	35.0000%
58	State Income Tax Rate		26-Tax Rates, Line 8	8.8400%
59	Composite Tax Rate	= F + [S * (1 - F)]	(L57 + L58) - (L57 * L58)	40.7460%
	Calculation of Credits and Other:			
60	Amortization of Excess Deferred Tax Liability	Note 3		$200
61	Investment Tax Credit Flowed Through	Note 3		-$520,000
62	South Georgia Income Tax Adjustment	Note 3		$2,606,000
63	Credits and Other		Line 60 + Line 61+ Line 62	$2,086,200
64	Income Taxes:		Formula on Line 65	$230,428,899
65	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			
	Where:			
	RB = Rate Base		Line 18	
	ER = Equity Rate of Return Including Common and Preferred Stock		Line 55	
	CTR = Composite Tax Rate		Line 59	
	CO = Credits and Other		Line 63	
	D = Book Depreciation of AFUDC Equity Book Basis		SCE Records	$3,296,636

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		**Notes**	**FERC Form 1 Reference or Instruction**	**2016 Value**
	PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT			
	Component of Prior Year TRR:			
66	O&M Expense		19-OandM, Line 91, Col. 6	$81,050,973
67	A&G Expense		20-AandG, Line 23	$52,426,004
68	Network Upgrade Interest Expense		22-NUCs, Line 8	$2,616,283
69	Depreciation Expense		17-Depreciation, Line 70	$230,409,242
70	Abandoned Plant Amortization Expense		12-AbandonedPlant, Line 1	$37,069,049
71	Other Taxes		Line 36	$58,568,952
72	Revenue Credits	Negative amount	21-Revenue Credits, Line 44	-$77,928,965
73	Return on Capital		Line 56	$435,673,172
74	Income Taxes		Line 64	$230,428,899
75	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	11-PHFU, Line 10	$0
76	Amortization and Regulatory Debits/Credits		23-RegAssets, Line 16	$0
77	Prior Year Incentive Adder		15-IncentiveAdder, Line 14	$36,662,105
78	Total without FF&U		Sum of Lines 66 to 77	$1,086,975,714
79	Franchise Fees Expense		L 78 * FF Factor (28-FFU, L 5)	$10,006,372
80	Uncollectibles Expense		L 78 * U Factor (28-FFU, L 5)	$2,617,003
81	Prior Year TRR		Line 78 + Line 79+ Line 80	$1,099,599,089
	TOTAL BASE TRANSMISSION REVENUE REQUIREMENT			
	Calculation of Base Transmission Revenue Requirement			
82	Prior Year TRR		Line 81	$1,099,599,089
83	Incremental Forecast Period TRR		2-IFPTRR, Line 82	$109,324,746
84	True Up Adjustment		3-TrueUpAdjust, Line 30	-$39,617,212
85	Cost Adjustment	Note 4		$0
86	Base Transmission Revenue Requirement (Retail)	For Retail Purposes	L 82 + L 83 + L 84 + L 85	$1,169,306,623
	Wholesale Base Transmission Revenue Requirement			
87	Base TRR (Retail)		Line 86	$1,169,306,623
88	Wholesale Difference to the Base TRR		25-WholesaleDifference, Line 45	-$6,395,449
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$1,162,911,173

Notes:

1) Any amount of "Sub-Total Local Taxes" or "Payroll Taxes Expense" may be excluded if appropriate with the provision of a workpaper showing the reason for the exclusion and the amount of the exclusion.
2) No change in Return on Common Equity will be made absent a Section 205 filing at the Commission.
Does not include any project-specific ROE adders.
In the event that the Return on Common Equity is revised from the initial value, enter cite to Commission Order approving the revised ROE on following line.
Order approving revised ROE:
3) No change in Amortization of Excess Deferred Tax Liability or South Georgia Income Tax Adjustment "Credits and Other" terms will be made absent a filing at the Commission. Investment Tax Credit Flowed Through amount shall be negative $520,000 through the Prior Year of 2018, negative $183,000 for the Prior Year of 2019, and $0 thereafter.
4) Cost Adjustment may be included as provided in the Tariff protocols.

Calculation of Incremental Forecast Period TRR ("IFPTRR")

The IFP TRR is equal to the sum of:
1) Forecast Plant Additions * AFCR
2) Forecast Period Incremental CWIP * AFCR for CWIP

1) Calculation of Annual Fixed Charge Rates:

Line			
	a) Annual Fixed Charge Rate for CWIP ("AFCRCWIP")		
1			
2	AFCRCWIP represents the return and income tax costs associated with $1 of CWIP,		
3	expressed as a percent.		
4			
5	AFCRCWIP = CLTD + (COS * (1/(1 - CTR)))		
6			
7	where:		
8	CLTD = Weighted Cost of Long Term Debt		
9	COS = Weighted Cost of Common and Preferred Stock		
10	CTR = Composite Tax Rate		
11			**Reference**
12	Wtd. Cost of Long Term Debt:	1.999%	1-BaseTRR, Line 51
13	Wtd. Cost of Common + Pref. Stock:	5.993%	1-BaseTRR, Line 55
14	Composite Tax Rate:	40.746%	1-BaseTRR, Line 59
15			
16	AFCRCWIP =	12.113%	Line 12 + (Line 13 * (1/(1 - Line 14)))
17			
18	**b) Annual Fixed Charge Rate ("AFCR")**		
19			
20	The AFCR is calculated by dividing the Prior Year TRR (without CWIP related costs)		
21	by Net Plant:		
22			
23	AFCR = (Prior Year TRR - CWIP-related costs) / Net Plant		
24			
25	**Determination of Net Plant:**		
26			**Reference**
27	Transmission Plant - ISO:	$8,276,570,295	6-PlantInService, Line 13
28	Distribution Plant - ISO:	$0	6-PlantInService, Line 16
29	Transmission Dep. Reserve - ISO:	$1,467,790,558	8-AccDep, Line 13
30	Distribution Dep. Reserve - ISO:	$0	8-AccDep, Line 16
31	Net Plant:	$6,808,779,737	(L27 + L28) - (L29 + L30)
32			
33	**Determination of Prior Year TRR without CWIP related costs:**		
34			
35	**a) Determination of CWIP-Related Costs**		
36	**1) Direct (without ROE adder) CWIP costs**		
37	CWIP Plant - Prior Year:	$115,749,706	10-CWIP, L 13 C1
38	AFCRCWIP:	12.113%	Line 16
39	Direct CWIP Related Costs:	$14,020,617	Line 37 * Line 38
40			
41	**2) CWIP ROE Adder costs:**		
42	IREF:	$8,538	15-IncentiveAdder, Line 3
43			
44	Tehachapi CWIP Amount:	$14,915,548	10-CWIP, Line 13
45	Tehachapi ROE Adder %:	1.25%	15-IncentiveAdder, Line 5
46	Tehachapi ROE Adder $:	$159,193	Formula on Line 52
47			
48	DCR CWIP Amount:	$0	10-CWIP, Line 13
49	DCR ROE Adder %:	1.00%	15-IncentiveAdder, Line 6
50	DCR ROE Adder $:	$0	Formula on Line 52
51			
52	ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)		
53			
54	CWIP Related Costs wo FF&U:	$14,179,809	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	$164,674	(28-FFU, L5 FF Factor + U Factor) * L54
56	CWIP Related Costs with FF&U:	$14,344,484	Line 54 + Line 55
57			

58	**b) Determination of AFCR:**		
59			
60	CWIP Related Costs wo FF&U:	$14,179,809	Line 54
61	Prior Year TRR wo FF&U:	$1,086,975,714	1-BaseTRR, Line 78
62	Prior Year TRR wo CWIP Related Costs:	$1,072,795,905	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	$100,107,733	(1-BaseTRR, Line 66 + Line 67) * .75
64	AFCR:	14.286%	(Line 62 - Line 63) / Line 31
65			
66	**2) Calculation of IFP TRR**		
67			
68			**Reference**
69	Forecast Plant Additions:	$658,584,613	16-PlantAdditions, L 25, C10
70	AFCR:	14.286%	Line 64
71	AFCR * Forecast Plant Additions:	$94,084,034	Line 69 * Line 70
72			
73	Forecast Period Incremental CWIP:	$115,461,165	10-CWIP, L 54, C8
74	AFCRCWIP:	12.113%	Line 16
75	AFCRCWIP * FP Incremental CWIP:	$13,985,666	Line 73 * Line 74
76			
77	IFPTRR without FF&U:	$108,069,700	Line 71 + Line 75
78			
79	Franchise Fees Expense:	$994,857	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	$260,189	Line 77 * U (from 28-FFU, L 5)
81			
82	Incremental Forecast Period TRR:	$109,324,746	Line 77 + Line 79 + Line 80

Calculation of True Up Adjustment Component of TRR

1) Summary of True Up Adjustment calculation:

a) Attribute True Up TRR to months in the Prior Year (see Note #1) to determine "Monthly True Up TRR" for each month (see Note #2).
b) Determine monthly retail transmission revenues attributable to this formula transmission rate received during Prior Year.
c) Compare costs in (a) to revenues in (b) on a monthly basis and determine "Cumulative Excess (-) or Shortfall (+) in Revenue with Interest".
d) Include previous Annual Update Cumulative Excess or Shortfall in Prior Year (from Previous Annual Update Line 23)
and any One-Time Adjustments in Column 4 (Lines 11 and 12 respectively).
e) Continue interest calculation through the end of the Prior Year (Line 23) to determine Cumulative Excess or Shortfall for this Annual Update.

**2) Comparison of True Up TRR and Actual Retail Transmission Revenues received during the Prior Year,
Including previous Annual Update Cumulative Excess or Shortfall in Revenue.**

Line										
1		True Up TRR:	$1,062,934,400	Source:	From 4-TUTRR,	Line 46				
2										
3		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
4	Calculations:		See Note 2	See Note 3	See Note 4	= C2 - C3 + C 4	See Note 5	See Note 6	See Note 7	=C7 + C8
5					One-Time			Cumulative		
6					Adjustments and			Excess (-) or		Cumulative
7				Actual	Shortfall/Excess	Monthly		Shortfall (+)		Excess (-) or
8			Monthly	Retail Base	Revenue In	Excess (-) or	Monthly	in Revenue	Interest	Shortfall (+)
9			True Up	Transmission	Previous	Shortfall (+)	Interest	wo Interest for	for Current	in Revenue
10	Month	Year	TRR	Revenues	Annual Update	in Revenue	Rate	Current Month	Month	with Interest
11	December	2015	---	---	$89,464,304	$89,464,304	---	$89,464,304	---	$89,464,304
12	January	2016	$88,577,866.68	$83,819,249	-$77,804	$4,680,814	0.27%	$94,145,118	$247,873	$94,392,990
13	February	2016	$88,577,866.68	$78,411,547		$10,166,320	0.27%	$104,559,310	$268,586	$104,827,896
14	March	2016	$88,577,866.68	$78,407,870		$10,169,996	0.27%	$114,997,892	$296,765	$115,294,657
15	April	2016	$88,577,866.68	$78,101,864		$10,476,003	0.29%	$125,770,660	$349,545	$126,120,204
16	May	2016	$88,577,866.68	$82,781,918		$5,795,949	0.29%	$131,916,153	$374,153	$132,290,306
17	June	2016	$88,577,866.68	$99,171,344		-$10,593,478	0.29%	$121,696,828	$368,281	$122,065,109
18	July	2016	$88,577,866.68	$109,857,523		-$21,279,656	0.29%	$100,785,453	$323,133	$101,108,587
19	August	2016	$88,577,866.68	$110,365,061		-$21,787,194	0.29%	$79,321,392	$261,623	$79,583,016
20	September	2016	$88,577,866.68	$92,876,534		-$4,298,667	0.29%	$75,284,348	$224,558	$75,508,906
21	October	2016	$88,577,866.68	$85,822,082		$2,755,784	0.29%	$78,264,690	$222,972	$78,487,662
22	November	2016	$88,577,866.68	$77,456,671		$11,121,196	0.29%	$89,608,858	$243,740	$89,852,598
23	December	2016	$88,577,866.68	$82,656,321	-$39,484,975	-$33,563,429	0.29%	$56,289,169	$211,906	$56,501,075

Line					
24	**4) True Up Adjustment**				
25			**Notes:**		
26	Shortfall or Excess Revenue in Prior Year:	$56,501,075	Line 23, Column 9		
27	Previous Annual Update TU Adjustment:	$ 94,152,863	Previous Annual Update Schedule 3, Line 30	Previous Annual Update:	TO11, filed in ER11-3697
28	TU Adjustment without Projected Interest	-$37,651,788	Line 26 - Line 27		on November 30, 2016
29	Projected Interest to Rate Year Mid-Point:	-$1,965,423	Line 28 * (Line 23, Column 6) * 18 months		
30	True Up Adjustment:	-$39,617,212	Line 28 + Line 29. Positive amount is to be collected by SCE (included in Base TRR as a positive amount).		
31			Negative amount is to be returned to customers by SCE (included in Base TRR as a negative amount).		

32 **5) Final True Up Adjustment**
33 The Final True Up Adjustment begins on the month after the last True Up Adjustment and extends through the termination date of
34 this formula transmission rate.
35 The Final True Up Adjustment shall be calculated as above, with interest to the termination date of the Formula Transmission Rate.
36

Line				
37	**Partial Year TRR Attribution Allocation Factors:**			
38			**Partial Year**	
39		**Month**	**TRR AAF**	**Note:**
40		January	6.376%	See Note 2.
41		February	5.655%	
42		March	7.183%	
43		April	8.224%	
44		May	8.018%	
45		June	8.945%	
46		July	9.891%	
47		August	10.141%	
48		September	10.218%	
49		October	9.179%	
50		November	7.530%	
51		December	8.640%	
52		Total:	100.000%	
53				

Line								
54	**Transmission Revenues: (Note 8)**							
55								
56		**Col 1**	**Col 2**	**Col 3**	**Col 4**	**Col 5**	**Col 6**	**Col 7**
57		See Note 9	See Note 10					Sum of left
58								
59		**Actual**						**Monthly**
60	**Prior**	**Retail Base**						**Total**
61	**Year**	**Transmission**	**Other**			**Public**		**Retail**
62	**Month**	**Revenues**	**Transmission**	**Distribution**	**Generation**	**Purpose**	**Other**	**Revenue**
63	Jan	$83,819,249	$6,811,238	$383,831,932	$279,105,623	$60,318,415	$19,896,742	$833,783,199
64	Feb	$78,411,547	$5,616,755	$354,097,563	$259,758,966	$44,144,014	$22,012,052	$764,040,897
65	Mar	$78,407,870	$6,071,447	$352,090,529	$272,973,750	$41,519,717	$21,804,701	$772,868,015
66	Apr	$78,101,864	$5,883,196	$192,849,912	$264,947,917	$40,353,366	$21,576,998	$603,713,253
67	May	$82,781,918	$6,184,822	$353,507,803	$277,910,682	$45,864,063	$22,300,327	$788,549,614
68	Jun	$99,171,344	-$3,145,703	$431,448,084	$544,814,544	$57,011,875	$27,650,219	$1,156,950,364
69	Jul	$109,857,523	-$3,673,062	$452,866,372	$597,674,239	$86,758,688	$30,904,781	$1,274,388,541
70	Aug	$110,365,061	-$3,591,852	$486,955,393	$604,298,112	$110,206,500	$30,975,483	$1,339,208,696
71	Sep	$92,876,534	-$3,063,996	$381,830,112	$495,235,552	$60,980,333	$25,699,568	$1,053,558,103
72	Oct	$85,822,082	-$2,772,450	$145,428,528	$303,295,334	$57,102,910	$23,195,857	$612,072,262
73	Nov	$77,456,671	-$2,615,199	$303,450,614	$264,085,093	$51,695,771	$21,276,717	$715,349,667
74	Dec	$82,656,321	-$2,690,298	$376,516,169	$281,781,780	$58,153,449	$22,468,963	$818,886,384
75	Totals:	$1,059,727,984	$9,014,898	$4,214,873,011	$4,445,881,591	$714,109,102	$289,762,408	$10,733,368,993
76								
77	"Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b:							$10,733,368,993

Instructions:

1) Enter applicable years on Column 1, Lines 11-23 (Prior Year and December of the year previous to the Prior Year).
2) Enter Previous Annual Update True Up Adjustment (if any) on Line 27.
   Enter with the same sign as in previous Annual Update. If there is no Previous Annual Update True Up Adjustment, then enter $0.
3) Enter monthly interest rates in accordance with interest rate specified in the regulations of FERC at
   18 C.F.R. §35.19a on lines 12 to 23, Column 6.
4) Enter any One Time Adjustments on Column 4, Line 12 (or other appropriate). If SCE is owed enter as positive, if SCE is to return to customers enter as negative.
   One Time Adjustments include:
   a) In the event that a Commission Order revises SCE's True Up TRR for a previous Prior Year,
      SCE shall include that difference in the True Up Adjustment, including interest, at the first opportunity, in accordance with tariff protocols.
      Entering on Line 12 (or other appropriate) ensures these One Time Adjustments are recovered from or returned to customers.
   b) Any refunds attributable to SCE's previous CWIP TRR cases (Docket Nos. ER08-375, ER09-187, ER10-160, and ER11-1952), not previously returned to customers.
   c) Amounts resulting from input errors impacting the True Up TRR in a previous Formula Rate Annual Update pursuant to Protocol Section 3(d)(8).
5) Fill in matrix of all retail revenues from Prior Year in table on lines 63 to 74.
6) Enter Total Sales to Ultimate Consumers on line 77 and verify that it equals the total on line 75.
7) If true up period is less than entire calendar year, then adjust calculation accordingly by including $0 Monthly True Up TRR and $0
   Actual Retail Base Transmission Revenues for any months not included in True Up Period.

Notes:

1) The true up period is the portion (all or part) of the Prior Year for which the Formula Transmission Rate was in effect.
2) The Monthly True Up TRR is derived by multiplying the annual True Up TRR on Line 1 by 1/12, if formula was in effect. In the event of
   a Partial Year True Up, use the Partial Year TRR Attribution Allocation Factors on Lines 40 to 51 for each month of Partial Year True Up.
   Only enter in the Prior Year, Lines 12 to 23, or portion of year formula was in effect in case of Partial Year True Up.
   Partial Year True Up Allocation Factors calculated based on three years (2008-2010) of monthly SCE retail base transmission revenues.
3) "Actual Retail Base Transmission Revenues" are SCE retail transmission revenues attributable to this formula transmission rate.
   as shown on Lines 63 to 74, Column 1.
4) Enter "Shortfall or Excess Revenue in Previous Annual Update" on Line 11, or other appropriate (from Previous Annual Update, Line 23, Column 9).
5) Monthly Interest Rates in accordance with interest rate specified in the regulations of FERC (See Instruction #3).
6) "Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month" is, beginning for the January month,
   the amount in Column 9 for previous month plus the current month amount in Column 5. For the first December, it is the amount in Column 5.
7) Interest for Current Month is calculated on average of beginning and ending balances (Column 9 previous month and Column 7 current month).
   No interest is applied for the first December.
8) Only provide if formula was in effect during Prior Year.
9) Only include Base Transmission Revenue attributable to this formula transmission rate.
   Any other Base Transmission Revenue or refunds is included in "Other".
   The Base Transmission Revenues shown in Column 1 shall be reduced to reflect any retail customer refunds provided by SCE associated with the
   formula transmission rate that are made through a CPUC-authorized mechanism.
10) Other Transmission Revenue includes the following:
   a) Transmission Revenue Balancing Account Adjustment revenue.
   b) Transmission Access Charge Balancing Account Adjustment.
   c) Reliability Services Revenue.
   d) Any Base Transmission Revenue not attributable to this formula.

Calculation of True Up TRR

A) Rate Base for True Up TRR

Line	Rate Base Item	Calculation Method	Notes	FERC Form 1 Reference or Instruction	Amount
1	ISO Transmission Plant	13-Month Avg.		6-PlantInService, Line 18	$7,902,835,352
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		6-PlantInService, Line 24	$275,543,182
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		11-PHFU, Line 9	$9,942,155
4	Abandoned Plant	BOY/EOY Avg.		12-AbandonedPlant Line 4	$18,534,525
	Working Capital Amounts				
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	$15,443,918
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	$5,099,704
7	Cash Working Capital	1/8 (O&M + A&G)		1-Base TRR Line 7	$16,684,622
8	Working Capital			Line 5 + Line 6 + Line 7	$37,228,244
	Accumulated Depreciation Reserve Amounts				
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	8-AccDep, Line 14, Col. 12	-$1,382,850,549
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	8-AccDep, Line 17, Col. 5	$0
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	8-AccDep, Line 23	-$119,467,537
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	-$1,502,318,086
13	Accumulated Deferred Income Taxes	BOY/EOY Avg.		9-ADIT, Line 14	-$1,384,321,610
14	CWIP Plant	13-Month Avg.		14-IncentivePlant, L 12, C2	$271,933,898
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	22-NUCs, Line 7	-$73,457,041
16	Unfunded Reserves			34-UnfundedReserves, Line 7	-$12,414,249
17	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		23-RegAssets, Line 15	$0
18	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L16+L17	$5,543,506,370

B) Return on Capital

Line					
19	Cost of Capital Rate		See Instruction 1	Instruction 1, Line j	7.4861%
20	Return on Capital: Rate Base times Cost of Capital Rate			Line 18 * Line 19	$414,992,552

C) Income Taxes

21	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			$214,940,745
	Where:			
22	RB = Rate Base		Line 18	$5,543,506,370
23	ER = Equity ROR inc. Com. and Pref. Stock	Instruction 1	Instruction 1, Line k	5.4867%
24	CTR = Composite Tax Rate		1-Base TRR L 59	40.7460%
25	CO = Credits and Other		1-Base TRR L 63	$2,086,200
26	D = Book Depreciation of AFUDC Equity Book Basis		1-Base TRR L 65	$3,296,636

D) True Up TRR Calculation

27	O&M Expense	1-Base TRR L 66	$81,050,973
28	A&G Expense	1-Base TRR L 67	$52,426,004
29	Network Upgrade Interest Expense	1-Base TRR L 68	$2,616,283
30	Depreciation Expense	1-Base TRR L 69	$230,409,242
31	Abandoned Plant Amortization Expense	1-Base TRR L 70	$37,069,049
32	Other Taxes	1-Base TRR L 71	$58,568,952
33	Revenue Credits	1-Base TRR L 72	-$77,928,965
34	Return on Capital	Line 20	$414,992,552
35	Income Taxes	Line 21	$214,940,745
36	Gains and Losses on Transmission Plant Held for Future Use -- Land	1-Base TRR L 75	$0
37	Amortization and Regulatory Debits/Credits	1-Base TRR L 76	$0
38	Total without True Up Incentive Adder	Sum Line 27 to Line 37	$1,014,144,834
39	True Up Incentive Adder	15-IncentiveAdder L 20	$36,587,101
40	True Up TRR without Franchise Fees and Uncollectibles Expense included:	Line 38 + Line 39	$1,050,731,935

E) Calculation of final True Up TRR with Franchise Fees and Uncollectibles Expenses

Line			**Reference:**
41	True Up TRR wo FF:	$1,050,731,935	Line 40
42	Franchise Fee Factor:	0.921%	28-FFU, L 5
43	Franchise Fee Expense:	$9,672,723	Line 41 * Line 42
44	Uncollectibles Expense Factor:	0.241%	28-FFU, L 5
45	Uncollectibles Expense:	$2,529,742	Line 43 * Line 44
46	True Up TRR:	$1,062,934,400	L 41 + L 43 + L 45

Instructions:

1) Use weighted average (by time) of the Return on Equity in effect during the Prior Year in determining the "Cost of Capital Rate" on Line 19 and the "Equity Rate of Return Including Preferred Stock" on Line 23 in the event that the ROE is revised during the Prior Year. In this event, the ROE used in Schedule 1 will differ from the ROE used in this Schedule 4, because the Schedule 1 ROE will be the most recent ROE, whereas the Schedule 4 Cost of Capital Rate and Equity Rate of Return including Com. + Pref. Stock will be based on the weighted-average ROE.

Calculation of weighted average Cost of Capital Rate in Prior Year:

If ROE does not change during year, then attribute all days to Line a "ROE at end of Prior Year" and none to "ROE at start of PY"

		Percentage	Reference:	From	To		Days ROE In Effect
a	ROE at end of Prior Year	9.80%	See Line e below	Jan 1, 2016	Dec 31, 2016		366
b	ROE start of Prior Year	9.80%	See Line f below				
c						Total days in year:	366
d	Wtd. Avg. ROE in Prior Year	9.80%	((Line a ROE * Line a days) + (Line b ROE * Line b days)) / Total Days in Year				

Commission Decisions approving ROE:

		Reference:
e	End of Prior Year	Settlement in ER11-3697
f	Beginning of Prior Year	Settlement in ER11-3697

		Percentage	Reference:
g	Wtd. Cost of Long Term Debt	1.9994%	1-Base TRR L 51
h	Wtd.Cost of Preferred Stock	0.5286%	1-Base TRR L 52
i	Wtd.Cost of Common Stock	4.9581%	1-Base TRR L 47 * Line d
j	Cost of Capital Rate	7.4861%	Sum of Lines g to i

Calculation of Equity Rate of Return Including Common and Preferred Stock:

	Percentage	Reference:
k	5.4867%	Sum of Lines h to i

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	2016 Value
	RETURN AND CAPITALIZATION CALCULATIONS			
	Calculation of Long Term Debt Amount			
1	Bonds -- Account 221	13-month avg.	5-ROR-2, Line 1	$10,326,762,637
2	Less Reacquired Bonds -- Account 222	13-month avg.	5-ROR-2, Line 2	-$50,769,231
3	Long Term Debt Advances from Associated Companies -- Account 223	13-month avg.	5-ROR-2, Line 3	$0
4	Other Long Term Debt -- Account 224	13-month avg.	5-ROR-2, Line 4	$306,652,104
5	Less Unamortized Discount on Long Term Debt -- Account 226	13-month avg.; enter negative	5-ROR-2, Line 6	-$35,385,188
6	Unamortized Debt Expenses -- Account 181	13-month avg.; enter negative	5-ROR-2, Line 7	-$81,582,699
7	Unamortized Loss on Reacquired Debt -- Account 189	13-month avg.; enter negative	5-ROR-2, Line 8	-$192,859,379
8	Composite Tax Rate		1-BaseTRR, Line 59	40.75%
9	After tax amount of Unamortized Loss on Reacquired Debt		Line 7 * (1- Line 8)	-$114,276,896
10	Removal of Long Term Debt Related to Fuel Inventories	13-month avg.; enter negative	5-ROR-2, Line 9	-$834,019,456
11	Adjustments related to "LT Debt Related to Fuel Inventories"		5-ROR-2, Line 10	$5,647,871
12	Long Term Debt Amount		Sum of Lines 1 to 6 and 9 to 11	$9,523,029,143
	Calculation of Preferred Stock Amount			
13	Preferred Stock Amount -- Account 204	13-month avg.	5-ROR-2, Line 11	$2,204,668,027
14	Unamortized Issuance Costs	13-month avg.	5-ROR-2, Line 12	-$44,689,190
15	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	5-ROR-2, Line 13	-$7,193,648
16	Preferred Stock Amount		Sum of Lines 13 to 15	$2,152,785,189
	Calculation of Common Stock Equity Amount			
17	Total Proprietary Capital	13-month avg.	5-ROR-2, Line 14	$14,131,533,164
18	Less Preferred Stock Amount -- Account 204	Same as L 13, but negative	5-ROR-2, Line 11	-$2,204,668,027
19	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 15, but reverse sign	5-ROR-2, Line 13	$7,193,648
20	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.	5-ROR-2, Line 15	$2,199,881
21	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg.	5-ROR-2, Line 16	$19,883,915
22	Common Stock Equity Amount		Sum of Lines 17 to 21	$11,956,142,581

Calculation of 13-Month Average Capitalization Balances

Year 2016

Line	Item	Col 1 13-Month Avg. = Sum (Cols. 2-14)/13	Col 2 December	Col 3 January	Col 4 February	Col 5 March	Col 6 April	Col 7 May	Col 8 June	Col 9 July	Col 10 August	Col 11 September	Col 12 October	Col 13 November	Col 14 December
	Bonds -- Account 221 (Note 1):														
1		$10,326,762,637	$10,375,114,286	$10,375,114,286	$10,335,828,571	$10,335,828,571	$10,335,828,571	$10,335,828,571	$10,335,828,571	$10,335,828,571	$10,296,542,857	$10,296,542,857	$10,296,542,857	$10,296,542,857	$10,296,542,857
	Reacquired Bonds -- Account 222 (Note 2): enter - of FF1														
2		-$50,769,231	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$30,000,000	-$165,000,000	-$165,000,000
	Long Term Debt Advances from Associated Companies (Note 3):														
3		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Other Long Term Debt -- Account 224 (Note 4):														
4		$306,652,104	$306,682,234	$306,677,289	$306,672,324	$306,667,338	$306,662,331	$306,657,303	$306,652,253	$306,647,182	$306,642,090	$306,636,977	$306,631,841	$306,626,685	$306,621,506
	Unamortized Premium on Long Term Debt -- Account 225 (Note 5)														
5		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Less Unamortized Discount on Long Term Debt -- Account 226 (Note 6): enter - of FF1														
6		-$35,385,188	-$36,460,491	-$36,280,813	-$36,113,113	-$35,921,457	-$35,747,768	-$35,562,101	-$35,388,413	-$35,202,746	-$35,023,068	-$34,849,379	-$34,663,712	-$34,490,023	-$34,304,356
	Unamortized Debt Expenses -- Account 181 (Note 7): enter - of FF1														
7		-$81,582,699	-$84,227,978	-$83,822,444	-$83,597,715	-$82,930,241	-$82,262,766	-$81,595,292	-$80,927,818	-$81,979,093	-$81,235,048	-$80,531,959	-$79,843,434	-$79,154,910	-$78,466,386
	Unamortized Loss on Reacquired Debt -- Account 189 (Note 8): enter - of FF1														
8		-$192,859,379	-$201,260,974	-$199,860,696	-$198,460,432	-$197,060,169	-$195,659,905	-$194,259,641	-$192,859,377	-$191,459,114	-$190,058,850	-$188,658,586	-$187,258,323	-$185,858,059	-$184,457,795
	Removal of Long Term Debt Related to Fuel Inventories (Note 9)														
9		-$834,019,456	-$889,696,723	-$885,308,257	-$876,159,152	-$848,953,189	-$842,321,120	-$835,689,051	-$829,056,982	-$822,424,914	-$815,792,845	-$809,160,776	-$802,528,707	-$795,896,638	-$789,264,569
	Adjustments related to "LT Debt Related to Fuel Inventories" (Note 10)														
10		$5,647,871	$5,953,291	$5,871,739	$6,023,977	$5,939,132	$5,854,288	$5,769,443	$5,684,598	$5,599,753	$5,514,909	$5,430,064	$5,345,219	$5,260,374	$5,175,530
	Preferred Stock Amount -- Account 204 (Note 11):														
11		$2,204,668,027	$2,070,044,950	$2,070,044,950	$2,070,044,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950	$2,245,054,950
	Unamortized Issuance Costs (Note 12): enter - of FF1														
12		-$44,689,190	-$42,446,729	-$42,205,342	-$41,963,956	-$48,682,380	-$46,242,352	-$45,950,127	-$45,657,902	-$45,365,677	-$45,073,451	-$44,781,226	-$44,489,001	-$44,196,776	-$43,904,550
	Net Gain (Loss) From Purchase and Tender Offers Note 13):														
13		-$7,193,648	-$5,797,402	-$5,765,077	-$5,732,751	-$7,848,228	-$7,798,004	-$7,747,780	-$7,697,556	-$7,647,332	-$7,597,108	-$7,546,883	-$7,496,659	-$7,446,435	-$7,396,211
	Total Proprietary Capital (Note 14):														
14		$14,131,533,164	$13,671,999,240	$13,803,506,473	$13,703,225,028	$13,943,224,209	$14,023,105,763	$14,129,499,735	$14,089,329,645	$14,216,652,406	$14,207,336,560	$14,349,798,497	$14,490,573,409	$14,598,893,351	$14,482,786,817
	Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 15): enter - of FF1														
15		$2,199,881	$2,026,801	$2,026,802	$2,027,196	$2,027,196	$2,027,699	$2,027,699	$2,013,499	$2,003,497	$2,003,497	$2,603,707	$2,603,709	$2,603,709	$2,603,436
	Accumulated Other Comprehensive Loss -- Account 219 (Note 16): enter - of FF1														
16		$19,883,915	$22,132,856	$22,060,494	$21,481,768	$20,949,399	$20,511,348	$20,201,806	$19,892,264	$18,664,081	$18,126,963	$18,530,070	$18,007,671	$17,485,272	$20,446,907

Instructions:

1) Enter 13 months of balances for capital structure for Prior Year and December previous to Prior Year in Columns 2-14.
Beginning and End of year amounts in Columns 2 and 14 are from FERC Form 1, as referenced in below notes.

Notes:

1) Amount in Column 2 from FF1 112.18d, amount in Column 14 from FF1 112.18c, amounts in columns 3-13 from SCE internal records.
2) Amount in Column 2 from FF1 112.19d, amount in Column 14 from FF1 112.19c, amounts in columns 3-13 from SCE internal records.
3) Amount in Column 2 from FF1 112.20d, amount in Column 14 from FF1 112.20c, amounts in columns 3-13 from SCE internal records.
4) Amount in Column 2 from FF1 112.21d, amount in Column 14 from FF1 112.21c, amounts in columns 3-13 from SCE internal records.
5) Amount in Column 2 from FF1 112.22c, amount in Column 14 from FF1 112.22d, amounts in columns 3-13 from SCE internal records.
6) Amount in Column 2 from FF1 112.23c, amount in Column 14 from FF1 112.23d, amounts in columns 3-13 from SCE internal records.
7) Amount in Column 2 from FF1 111.69c, amount in Column 14 from FF1 111.69d, amounts in columns 3-13 from SCE internal records.
8) Amount in Column 2 from FF1 111.81c, amount in Column 14 from FF1 111.81d, amounts in columns 3-13 from SCE internal records.
9) Amounts in Columns 2-14 are from SCE internal records.
10) Amounts in Columns 2-14 are from SCE internal records.
11) Amount in Column 2 from FF1 112.3d, amount in Column 14 from FF1 112.3c, amounts in columns 3-13 from SCE internal records.
12) Amounts in Columns 2-14 are from SCE internal records.
13) Amounts in Columns 2-14 are from SCE internal records.
14) Amount in Column 2 from FF1 112.16c, amount in Column 14 from FF1 112.16d, amounts in columns 3-13 from SCE internal records.
15) Amount in Column 2 from FF1 112.12c, amount in Column 14 from FF1 112.12d, amounts in columns 3-13 from SCE internal records.
16) Amount in Column 2 from FF1 112.15c, amount in Column 14 from FF1 112.15d, amounts in columns 3-13 from SCE internal records.

Long Term Debt Cost Percentage
At End of Year ("EOY") for Prior Year: 2016

1) Calculation of "Long Term Debt Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Outstanding Series Debt:	$456,504,134	Line 200, Col 10
2	Total Annual Amortized Loss on Reacquired Debt:	$16,803,179	Line 500, Col 3
3	Total Annual Cost of Debt:	$473,307,313	= L1 + L2
4			
5	Total "Principal Amount Outstanding" Debt:	$9,813,899,794	Line 200, Col 5
6	Total Reacquired Debt:	-$165,000,000	Line 205, Col 5
7	Total Unamortized Loss on Reacquired Debt:	-$109,489,851	Line 500, Col 2
8	Total Debt Balance:	$9,539,409,942	= L5 + L6 + L7
9			
10	Long Term Debt Cost Percentage:	4.962%	= L3 / L8

2) Long Term Debt Information for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	
	FF1 256, Col a	FF1 256, Col d	FF1 256, Col e	FF1 256, Col a	FF1 256, Col b	Note 1	Section 4	= Col 5 - Col 7	Note 2	= Col 5 * Col 9	
Line	Series	Date of Offering	Maturity Date	Coupon Rate	Principal Amount Outstanding ($000s)	Amort-ization Period (Years)	Net Discount & Issuance Cost ($000s)	Net Proceeds ($000s)	Cost of Money	Annual Cost ($000s)	Comments: See below
101	Series 2004B	1/14/2004	1/15/2034	6.000%	$525,000	17.0	$4,802	$520,198	6.087%	$31,957	
102	Series PV 2000AB	3/1/2004	6/1/2035	5.000%	$144,400	18.0	$443	$143,957	5.026%	$7,258	
103	Series 2004G	3/23/2004	4/1/2035	5.750%	$350,000	18.0	$1,920	$348,080	5.799%	$20,298	
104	Series 2005B	1/19/2005	1/15/2036	5.550%	$250,000	19.0	$1,912	$248,088	5.616%	$14,040	
105	Series 2005E	6/27/2005	7/15/2035	5.350%	$350,000	19.0	$2,025	$347,975	5.399%	$18,897	
106	Series 4CRNRS 05AB	4/1/2015	4/1/2029	1.875%	$203,460	12.0	$2,008	$201,452	1.968%	$4,004	
107	Clark County 2010	4/1/2015	6/1/2031	1.875%	$75,000	14.0	$1,107	$73,893	1.996%	$1,497	
108	Series 2006A	1/31/2006	2/1/2036	5.625%	$350,000	19.0	$2,732	$347,268	5.693%	$19,925	
109	SONGS_2006A	4/5/2013	4/1/2028	1.375%	$157,500	11.0	$743	$156,757	1.421%	$2,239	
110	SONGS_2006B	4/5/2013	4/1/2028	1.900%	$38,500	11.0	$252	$38,248	1.966%	$757	
111	Series 2006C&D	4/12/2006	11/1/2033	0.694%	$135,000	17.0	$925	$134,075	0.737%	$995	1
112	Series 2006E	12/11/2006	1/15/2037	5.550%	$400,000	20.0	$4,133	$395,867	5.637%	$22,547	
113	Series 2008A	1/22/2008	2/1/2038	5.950%	$600,000	21.0	$6,397	$593,603	6.040%	$36,242	
114	Series 2008B	8/18/2008	8/15/2018	5.500%	$400,000	2.0	$896	$399,104	5.620%	$22,480	
115	Series 2009A	3/20/2009	3/15/2039	6.050%	$500,000	22.0	$6,815	$493,185	6.164%	$30,820	
116	Series 2010A	3/11/2010	3/15/2040	5.500%	$500,000	23.0	$8,804	$491,196	5.638%	$28,188	
117	Series 2010B	8/30/2010	9/1/2040	4.500%	$500,000	24.0	$6,708	$493,292	4.593%	$22,964	
118	SONGS 2010A	9/21/2010	9/1/2029	4.500%	$100,000	13.0	$1,337	$98,663	4.638%	$4,638	
119	2011A	5/17/2011	6/1/2021	3.875%	$500,000	4.0	$3,154	$496,846	4.047%	$20,237	
120	2011E	11/22/2011	12/1/2041	3.900%	$250,000	25.0	$3,405	$246,595	3.987%	$9,966	
121	2012A	3/13/2012	3/15/2042	4.050%	$400,000	25.0	$7,582	$392,418	4.173%	$16,691	
122	2013A	3/7/2013	3/15/2043	3.900%	$400,000	26.0	$5,854	$394,146	3.991%	$15,964	
123	2013C	10/2/2013	10/1/2023	3.500%	$600,000	7.0	$4,244	$595,756	3.615%	$21,692	
124	2013D	10/2/2013	10/1/2043	4.650%	$800,000	27.0	$12,708	$787,292	4.755%	$38,041	
125	2014B	5/9/2014	5/1/2017	1.125%	$400,000	0.4	$294	$399,706	1.303%	$5,211	
126	2014C	11/7/2014	11/1/2017	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2
127	2015A	1/26/2015	2/1/2022	1.845%	$38,742	5.0	$291	$38,451	2.004%	$776	3
128	2015B	1/26/2015	2/1/2022	2.400%	$29,136	5.0	$174	$28,962	2.528%	$737	4
129	2015C	1/26/2015	2/1/2045	3.600%	$425,000	28.0	$5,912	$419,088	3.680%	$15,640	
130	4CRNRS 2011	4/1/2015	4/1/2029	1.875%	$55,540	12.0	$799	$54,741	2.011%	$1,117	
131	CPCFA SONGS 2011	9/1/1999	9/1/2031	0.407%	$30,000	15.0	$257	$29,743	0.466%	$140	5
132	CPCFA SONGS 2011	9/1/2011	9/1/2031	N/A	N/A	N/A	N/A	N/A	N/A	N/A	6
133	Series 2006C&D	4/12/2006	11/1/2033	N/A	N/A	N/A	N/A	N/A	N/A	N/A	7
134	6.65% Notes	4/1/1999	4/1/2029	6.650%	$300,000	12.0	$2,143	$297,857	6.738%	$20,213	
135	Ft. Irwin Loan	9/1/2003	9/1/2053	5.060%	$6,622	37.0	$0	$6,622	5.060%	$335	8
136	…										

Comments for Section 2 "Long Term Debt Information for each Outstanding Series":

Comment #:	Comment
1	Issued in April 2006 @ 0.694%, Repurchased on 11/01/16, Remarketed on 1/18/17 @ 2.625%
2	Not include because it is a fuel bond and does not finance rate base
3	Does not tie to FF1 amount because only includes Excess Regulatory Asset Amount
4	Does not tie to FF1 amount because only includes Excess Regulatory Asset Amount
5	FF1 has the variable rate. 0.407% is based on average of January through December in 2016
6	Reacquired series are shown below in Section 3 see line 202
7	Reacquired series are shown below in Section 3 see line 201
8	Principal amount reduces over time. FF1 amount reflects principal balance on the date of offering.

200 **Total Principal Amount Outstanding (sum of above * 1,000):** $9,813,899,794 **Total Annual Cost (sum of above * 1,000):** $456,504,133.56

3) Long Term Debt Information for each Reacquired Series

	Col 1	Col 2	Col 3	Col 4	Col 5	
	Series	**Date of Offering**	**Maturity Date**	**Coupon Rate**	**Principal Amount ($000s)**	**Comment #**
201	SONGS 2006 Series C-D	4/6/2006	11/1/2033	0.694%	-$135,000	
202	SONGS 2011 Series	9/1/2011	9/1/2031	0.407%	-$30,000	
203						
204	…					
205		**Total Principal Amount (sum of above * 1,000):**			-$165,000,000	

Comments for Section 3 "Long Term Debt Information for each Reacquired Series":

Comment #:	Comment

4) Debt Issuance Cost and Discount Details for each Outstanding Series

Line	Col 1 Series	Col 2 Unamortized Debt Issuance Cost (Dec of Prior Year)	Col 3 Total Unamortized Debt Discounts (Dec of PY)
301	Series 2004B	$2,831,262	$1,970,790
302	Series PV 2000AB	$443,347	$0
303	Series 2004G	$1,828,999	$90,591
304	Series 2005B	$1,461,700	$450,552
305	Series 2005E	$1,921,328	$103,679
306	Series 4CRNRS 05AB	$2,007,585	$0
307	Clark County 2010	$1,107,493	$0
308	Series 2006A	$2,186,987	$545,467
309	SONGS_2006A	$742,631	$0
310	SONGS_2006B	$251,581	$0
311	Series 2006C&D	$925,424	$0
312	Series 2006E	$2,683,762	$1,448,962
313	Series 2008A	$4,458,923	$1,938,055
314	Series 2008B	$527,167	$368,530
315	Series 2009A	$3,782,562	$3,032,221
316	Series 2010A	$4,136,621	$4,666,895
317	Series 2010B	$4,199,972	$2,508,428
318	SONGS 2010A	$1,337,234	$0
319	2011A	$1,884,665	$1,268,902
320	2011E	$2,243,191	$1,162,175
321	2012A	$3,610,491	$3,971,497
322	2013A	$3,769,406	$2,084,378
323	2013C	$3,531,228	$712,997
324	2013D	$7,800,285	$4,908,176
325	2014B	$280,004	$14,288
326	2015A	$291,010	$0
327	2015B	$172,979	$1,478
328	2015C	$4,385,519	$1,526,922
329	4CRNRS 2011	$798,972	$0
330	CPCFA SONGS 2011	$256,667	$0
331	6.65% NOTES	$667,050	$1,476,130
332	Ft. Irwin Loan	$0	$0
333			
334	…		

5) Loss on Reacquired Debt Cost Details

Line	Col 1 Series	Col 2 Unamortized Loss (Dec of PY) ('000s)	Col 3 Amortized Loss ('000s)
401	86-B	-$522	$506
402	86-B	-$50	$49
403	86-A	-$1,240	$246
404	88-C	-$1,315	$261
405	VVP,WWP,XXP,YYP	-$777	$203
406	89-A	$0	$0
407	89-A	-$3,067	$567
408	86-A	-$5,125	$1,098
409	MM	-$382	$649
410	ZZ	-$1,411	$1,263
411	VVP-WWP-YYP	-$639	$251
412	85-A	-$681	$255
413	85-C	-$349	$780
414	85-C	-$556	$157
415	86-K	$0	$0
416	86-K	-$186	$342
417	86-K	$0	$1
418	91-B	-$2,114	$562
419	91-C	-$2,406	$546
420	91-A	-$3,175	$436
421	86J, 88D & 87E-H	-$1,413	$188
422	190-PV-85B-G	-$122	$11
423	100-MOH-87-A	-$172	$20
424	MOHAVE-90A-15M	-$104	$12
425	93C, 93G, 93I & QUIP	-$4,013	$396
426	93C, 93G & 93I Premium	-$3,572	$353
427	2004B (Hedge)	-$1,756	$173
428	2004G (Hedge)	-$877	$81
429	2003A	$0	$0
430	2003B	-$22,407	$1,974
431	2003B	-$7,200	$651
432	2005E (Hedge)	-$1,477	$134
433	91-D(PC)-28.585M	-$214	$19
434	92-C(PC)-30M	-$449	$41
435	92-E(PC)-190M	-$2,013	$182
436	CA'86-D-G-196M	-$47	$7
437	CA-84-A/(86-D-G)	-$68	$10
438	CA'87-A-D-135M	-$193	$19
439	CA-84-A/(86-D-G) SWAP	-$2,053	$306

5) Loss on Reacquired Debt Cost Details (Continued)

Line	Col 1 Series	Col 2 Unamortized Loss (Dec of PY) ('000s)	Col 3 Amortized Loss ('000s)
440	2006E (Hedge)	-$3,510	$293
441	#2008A (Hedge)$21,372,964.	-$8,982	$712
442	#2008B (Hedge)$11,410,320.	-$1,108	$1,142
443	Reamarketed - 5/27/10	-$111	$55
444	Refunded - 9/24/10	-$4,412	$582
445	Refunded-5/19/11 (4Crnrs 1999A)	-$261	$36
446	Refunded-5/19/11 (4Crnrs 1999A)	-$93	$13
447	Retired 12/01/2011	-$706	$63
448	Reamarketed - 4/5/2013	-$668	$99
449	2004A Retired Bond Premium	-$5,644	$353
450	2008C Retired Bond Premium	-$1,884	$118
451	2015C	-$9,965	$591
452	…		
500	**Totals (sum of above * 1000):**	-$109,489,851	$16,803,179

Notes:

1) Equal to maturity date less end of the year for prior year
2) 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money

Preferred Stock Cost Percentage
At End of Year ("EOY") for Prior Year: 2016

1) Calculation of "Preferred Stock Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Preferred Stock:	$129,238,029	Line 112, Col 9
2	Total Reacquired Preferred Stock Cost:	$602,688	Line 312, Col 6
3	Total Annual Cost of Preferred:	$129,840,717	= L1 + L2
4			
5	Total Preferred Stock Amount Outstanding:	$2,245,054,950	Line 112, Col 4
6	Total Unamortized Issuance Costs:	$7,396,211	Line 312, Col 4
7	Total Preferred Balance:	$2,237,658,739	= L5 - L6
8			
9	Preferred Stock Cost Percentage:	5.803%	= L3 / L7

2) Preferred Stock Information for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	
	FF1 250, Col a	SCE Records	FF1 250, Col a	FF1 251, Col f	Sec 3, Col 2	= Col 4 - Col 5	= Col 6 / Col 4	= Col 3 / Col 7	= Col 4 * Col 8	
Line	Preferred Stock	Issue Date	Dividend Rate	Face Value / Amount Oustanding ('000s)	Total Issuance Cost ('000s)	Net Proceeds at Issuance ('000s)	% of Face Value	Cost of Money / Effective Rate	Annualized Cost ('000s)	Notes
101	$25 Par Value 4.32% Series	5/8/1947	4.320%	$41,336	-$763	$42,099	101.8%	4.242%	$1,753	
102	$25 Par Value 4.08% Series	5/19/1950	4.080%	$16,250	-$40	$16,290	100.2%	4.070%	$661	
103	$25 Par Value 4.24% Series	2/15/1956	4.240%	$30,000	-$84	$30,084	100.3%	4.228%	$1,268	
104	$25 Par Value 4.78% Series	2/10/1958	4.780%	$32,419	-$50	$32,469	100.2%	4.773%	$1,547	
105	Series E	1/17/2012	6.250%	$350,000	$5,957	$344,043	98.3%	6.483%	$22,689	
106	Series F	5/18/2012	5.625%	$475,010	$15,402	$459,608	96.8%	5.855%	$27,812	
107	Series G	1/29/2013	5.100%	$400,010	$12,972	$387,038	96.8%	5.317%	$21,268	
108	Series H	3/6/2014	5.750%	$275,010	$6,272	$268,738	97.7%	6.056%	$16,654	
109	Series J	8/24/2015	5.375%	$325,010	$6,420	$318,590	98.0%	5.635%	$18,313	
110	Series K	3/8/2016	5.450%	$300,010	$6,960	$293,050	97.7%	5.757%	$17,271	
111	…									
112	**Total Amount Outstanding (sum of above * 1,000):**			$2,245,054,950		**Total Annual Cost (sum of above * 1,000):**			$129,238,029	

3) Preferred Stock Issuance Cost Details for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4	Col 5
	Same list as in Section 2	SCE Records	SCE Records	SCE Records	
Line	Preferred Stock	Total Issuance Cost ('000s)	Unamortized Issuance Cost ('000s)	Full Amortization Period	Notes
201	$25 Par Value 4.32% Series	-$763	---	30	Fully amortized
202	$25 Par Value 4.08% Series	-$40	---	30	Fully amortized
203	$25 Par Value 4.24% Series	-$84	---	30	Fully amortized
204	$25 Par Value 4.78% Series	-$50	---	30	Fully amortized
205	Series E	$5,957	$3,028	10	
206	Series F	$15,402	$13,049	30	
207	Series G	$12,972	$11,279	30	Redeemed Series B and C
208	Series H	$6,272	$4,547	10	
209	Series J	$6,420	$5,564	10	
210	Series K	$6,960	$6,438	10	Redeemed Series D
211	…				

4) Reacquired Preferred Stock Information

Line	Col 1 SCE Records Preferred Stock	Col 2 SCE Records Call Date	Col 3 SCE Records Total Issuance Cost	Col 4 SCE Records Unamortized Issuance Cost ('000s)	Col 5 SCE Records Amortization Period	Col 6 SCE Records Issuance Amortization Cost ('000s)	Notes
301	8.540% Preferred, premium	11/1/1985	-$287	-$24	34	-$8	Net gain from open-market purchase of 67,400 shares in November 1985
302	12.000% Preferred, redemption	2/1/1986	$6,248	$567	34	$184	Redemption premium paid to holders (so loss to company)
303	12.000% Preferred, redemption	2/1/1986	$1,025	$93	34	$30	Initial issue discount
304	Series A	6/16/2012	$0	$0	5	$0	Fully amortized
305	Series B	2/28/2013	$2,586	$2,256	30	$86	Redeemed by Series G
306	Series C	2/28/2013	$2,887	$2,518	30	$96	Redeemed by Series G
307	Series D	3/31/2016	$2,148	$1,987	10	$215	Series D was redeemed by Series K
308							
309							
310							
311	…						
312	**Total Annual Cost (sum of above * 1,000):**			$7,396,211		$602,688	

Plant In Service

Inputs are shaded yellow

1) Transmission Plant - ISO

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year (See Note 1): Prior Year: **2016**

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
Line	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	Dec 2015	$77,976,655	163,072,480	$470,458,376	$3,030,177,247	$2,164,622,763	$310,678,566	$1,239,646,181	$221,416	$13,011,928	$187,087,541	$7,656,953,152
2	Jan 2016	$77,366,106	$163,089,425	$477,787,637	$3,038,238,129	$2,149,854,075	$312,467,579	$1,241,589,579	$221,419	$13,016,282	$187,350,498	$7,660,980,730
3	Feb 2016	$77,365,696	$163,086,102	$470,257,229	$3,058,743,183	$2,152,015,903	$313,580,382	$1,242,505,439	$221,419	$13,016,547	$187,651,223	$7,678,443,123
4	Mar 2016	$87,298,557	$163,152,630	$476,439,568	$3,076,643,567	$2,150,669,453	$315,593,553	$1,245,422,772	$221,419	$13,020,184	$190,200,199	$7,718,661,901
5	Apr 2016	$87,309,335	$163,197,609	$491,408,710	$3,089,452,188	$2,155,881,434	$316,787,447	$1,245,937,741	$221,425	$14,735,210	$190,592,880	$7,755,523,977
6	May 2016	$87,317,065	$163,204,896	$491,870,167	$3,090,721,159	$2,149,317,764	$317,533,976	$1,246,282,243	$221,425	$15,083,340	$191,019,613	$7,752,571,648
7	Jun 2016	$86,794,533	$162,983,298	$496,064,461	$3,120,246,532	$2,210,512,877	$318,450,055	$1,247,245,617	$221,434	$15,146,687	$192,180,089	$7,849,845,584
8	Jul 2016	$86,801,874	$162,990,137	$501,268,132	$3,170,862,943	$2,212,689,387	$319,127,828	$1,247,320,275	$221,435	$15,149,825	$192,445,155	$7,908,876,992
9	Aug 2016	$86,799,926	$163,006,399	$501,046,195	$3,171,072,527	$2,228,283,811	$319,715,189	$1,241,488,154	$221,437	$15,146,092	$178,450,654	$7,905,230,384
10	Sep 2016	$86,814,704	$165,199,257	$502,725,446	$3,174,643,082	$2,227,591,400	$320,439,816	$1,245,055,136	$178,517,523	$77,483,575	$178,430,166	$8,156,900,104
11	Oct 2016	$86,813,903	$165,297,497	$517,665,602	$3,188,871,202	$2,231,665,227	$321,310,132	$1,251,456,010	$180,892,151	$80,351,534	$179,079,774	$8,203,403,034
12	Nov 2016	$86,821,377	$165,325,104	$520,661,331	$3,201,337,814	$2,220,025,052	$322,121,103	$1,251,410,453	$184,358,841	$81,550,530	$179,287,045	$8,212,898,650
13	Dec 2016	$86,845,703	$165,326,927	$531,582,611	$3,249,175,449	$2,233,991,232	$324,258,228	$1,235,903,790	$185,508,197	$81,951,072	$182,027,087	$8,276,570,295
14	13-Mo. Avg:	$84,794,264	$163,763,982	$496,095,036	$3,127,706,540	$2,191,316,952	$317,851,066	$1,244,712,569	$56,251,503	$34,512,524	$185,830,917	$7,902,835,352

2) Distribution Plant - ISO

Balances for Distribution Plant - ISO for December of Prior Year and year before Prior Year (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5
					Sum C2 - C4
Line	**Mo/YR**	**360**	**361**	**362**	**Total**
15	Dec 2015	$0	$0	$0	$0
16	Dec 2016	$0	$0	$0	$0
17	Average:	$0	$0	$0	$0

3) ISO Transmission Plant

ISO Transmission Plant is the sum of "Transmission Plant - ISO" and "Distribution Plant - ISO"

Line		Amount	Source
18	Average value:	$7,902,835,352	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value:	$8,276,570,295	Sum of Line 13, Col 12 and Line 16, Col 5

4) General Plant + Electric Miscellaneous Intangible Plant ("G&I Plant")

General and Intangible Plant is an allocated portion of Total G&I Plant based on the Trans. W&S Allocation Factor

Line	Note 1 Prior Year Month	Data Source	Col 1 General Plant Balances	Col 2 Intangible Plant Balances	Col 3 Total G&I Plant Balances	Notes
20	December	FF1 206.99.b and 204.5b	$2,810,955,447	$1,597,954,444	$4,408,909,891	BOY amount from previous PY
21	December	FF1 207.99.g and 205.5g	$2,941,903,413	$1,588,136,353	$4,530,039,766	End of year ("EOY") amount

Line	a) BOY/EOY Average G&I Plant	Amount	Source
22	Average BOY/EOY Value:	$4,469,474,829	Average of Line 20 and 21.
23	Transmission W&S Allocation Factor:	6.1650%	27-Allocators, Line 9
24	General + Intangible Plant:	$275,543,182	Line 22 * Line 23.

Line	b) EOY G&I Plant	Amount	Source
25	EOY Value:	$4,530,039,766	Line 21.
26	Transmission W&S Allocation Factor:	6.1650%	27-Allocators, Line 9
27	General + Intangible Plant:	$279,277,011	Line 25 * Line 26.

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

1) Total Transmission Plant Balances by Account (See Note 3)

Line	Col 1 Mo/YR	Col 2 350.1	Col 3 350.2	Col 4 352	Col 5 353	Col 6 354	Col 7 355	Col 8 356	Col 9 357	Col 10 358	Col 11 359	Col 12 Sum C2 - C11 Total
28	Dec 2015	$121,657,932	$206,772,796	$686,827,404	$5,247,711,807	$2,259,972,826	$1,008,567,359	$1,482,107,624	$61,087,062	$268,612,323	$194,018,041	$11,537,335,173
29	Jan 2016	$120,041,817	$206,793,885	$703,336,512	$5,261,334,182	$2,267,078,142	$1,019,274,095	$1,490,923,946	$62,025,505	$270,314,278	$194,248,889	$11,595,371,251
30	Feb 2016	$120,040,731	$206,789,749	$697,204,660	$5,284,584,037	$2,269,281,264	$1,030,145,034	$1,492,010,547	$62,000,535	$270,417,583	$194,553,636	$11,627,027,777
31	Mar 2016	$129,974,728	$206,872,547	$711,236,847	$5,314,778,263	$2,270,538,592	$1,055,295,897	$1,501,940,681	$62,027,745	$271,839,478	$203,547,852	$11,728,052,629
32	Apr 2016	$129,984,883	$206,918,508	$747,798,350	$5,334,716,094	$2,271,061,823	$1,068,519,519	$1,502,283,885	$64,354,798	$281,803,117	$204,247,360	$11,811,688,337
33	May 2016	$129,993,235	$206,927,466	$748,915,253	$5,336,971,167	$2,274,749,703	$1,077,180,002	$1,502,976,156	$64,594,822	$283,742,241	$205,412,540	$11,831,462,585
34	Jun 2016	$129,471,531	$206,521,861	$758,346,667	$5,386,916,234	$2,255,499,746	$1,095,086,005	$1,505,142,344	$67,845,750	$307,996,467	$208,722,402	$11,921,549,006
35	Jul 2016	$129,475,315	$206,529,508	$770,153,637	$5,472,385,653	$2,255,378,799	$1,103,011,206	$1,504,634,374	$68,453,757	$308,991,821	$209,245,602	$12,028,259,671
36	Aug 2016	$129,472,250	$206,549,342	$769,327,743	$5,472,858,383	$2,275,896,336	$1,113,130,924	$1,499,109,785	$69,115,779	$307,862,523	$195,235,924	$12,038,558,989
37	Sep 2016	$129,486,155	$209,278,479	$771,511,221	$5,478,846,800	$2,277,142,361	$1,123,636,141	$1,508,232,675	$248,255,065	$370,623,767	$195,222,055	$12,312,234,718
38	Oct 2016	$129,485,354	$209,396,750	$805,401,883	$5,503,702,709	$2,286,042,052	$1,133,087,097	$1,515,768,067	$244,462,304	$372,715,446	$195,800,868	$12,395,862,531
39	Nov 2016	$129,492,828	$209,426,561	$812,167,139	$5,524,691,107	$2,291,044,950	$1,143,622,431	$1,513,544,440	$252,813,478	$368,838,528	$196,000,838	$12,441,642,299
40	Dec 2016	$ 129,517,154	$ 209,428,813	$825,778,508	$5,586,246,880	$2,305,498,226	$1,158,164,968	$1,499,811,260	$253,220,290	$368,734,329	$200,535,234	$12,536,935,662

2) Total Transmission Activity by Account (See Note 4):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
41	Jan 2016	-$1,616,115	$21,089	$16,509,109	$13,622,375	$7,105,317	$10,706,736	$8,816,323	$938,443	$1,701,955	$230,848	$58,036,078
42	Feb 2016	-$1,086	-$4,136	-$6,131,852	$23,249,856	$2,203,121	$10,870,939	$1,086,601	-$24,970	$103,305	$304,748	$31,656,526
43	Mar 2016	$9,933,998	$82,797	$14,032,187	$30,194,226	$1,257,328	$25,150,863	$9,930,133	$27,210	$1,421,895	$8,994,215	$101,024,852
44	Apr 2016	$10,154	$45,962	$36,561,503	$19,937,831	$523,231	$13,223,623	$343,204	$2,327,053	$9,963,639	$699,509	$83,635,708
45	May 2016	$8,353	$8,958	$1,116,903	$2,255,074	$3,687,881	$8,660,482	$692,271	$240,024	$1,939,124	$1,165,179	$19,774,248
46	Jun 2016	-$521,704	-$405,606	$9,431,414	$49,945,067	-$19,249,957	$17,906,003	$2,166,188	$3,250,929	$24,254,225	$3,309,862	$90,086,421
47	Jul 2016	$3,784	$7,647	$11,806,970	$85,469,419	-$120,947	$7,925,201	-$507,970	$608,007	$995,354	$523,200	$106,710,665
48	Aug 2016	-$3,065	$19,834	-$825,894	$472,730	$20,517,538	$10,119,719	-$5,524,589	$662,022	-$1,129,298	-$14,009,678	$10,299,318
49	Sep 2016	$13,905	$2,729,137	$2,183,478	$5,988,417	$1,246,025	$10,505,217	$9,122,891	$179,139,286	$62,761,244	-$13,869	$273,675,729
50	Oct 2016	-$801	$118,272	$33,890,663	$24,855,909	$8,899,691	$9,450,956	$7,535,391	-$3,792,760	$2,091,679	$578,813	$83,627,813
51	Nov 2016	$7,474	$29,811	$6,765,256	$20,988,399	$5,002,898	$10,535,333	-$2,223,627	$8,351,174	-$3,876,918	$199,970	$45,779,768
52	Dec 2016	$24,326	$2,251	$13,611,369	$61,555,773	$14,453,276	$14,542,537	-$13,733,180	$406,812	-$104,199	$4,534,396	$95,293,362
53	Total:	$7,859,222	$2,656,017	$138,951,104	$338,535,073	$45,525,400	$149,597,609	$17,703,636	$192,133,228	$100,122,006	$6,517,193	$999,600,489

3) ISO Incentive Plant Balances (See Note 5)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	Dec 2015	$9,194,807	$94,260,653	$264,762,214	$1,088,156,186	$1,705,207,064	$149,246,224	$827,237,632	$0	$11,017,487	$147,473,890	$ 4,296,556,157
55	Jan 2016	$9,194,807	$94,260,653	$264,864,093	$1,088,146,837	$1,706,416,314	$150,319,161	$826,634,499	$0	$11,017,487	$147,748,675	$ 4,298,602,525
56	Feb 2016	$9,194,807	$94,260,653	$256,232,589	$1,104,668,933	$1,708,608,305	$150,648,404	$827,487,097	$0	$11,017,487	$148,047,918	$ 4,310,166,193
57	Mar 2016	$19,126,978	$94,260,653	$256,234,668	$1,104,729,831	$1,709,163,793	$150,803,662	$827,806,072	$0	$11,017,487	$148,222,876	$ 4,321,366,020
58	Apr 2016	$19,138,135	$94,301,613	$254,203,939	$1,107,193,320	$1,710,950,861	$151,031,592	$828,384,682	$0	$12,711,355	$148,502,541	$ 4,326,418,038
59	May 2016	$19,145,486	$94,302,070	$254,149,357	$1,107,031,366	$1,711,875,469	$151,142,646	$828,600,329	$0	$13,055,405	$148,657,277	$ 4,327,959,406
60	Jun 2016	$18,622,453	$94,832,891	$254,220,416	$1,106,925,903	$1,714,309,220	$150,694,466	$829,118,042	$0	$13,056,703	$149,026,056	$ 4,330,806,150
61	Jul 2016	$18,631,953	$94,836,423	$254,225,247	$1,106,967,423	$1,714,807,545	$150,790,284	$829,408,573	$0	$13,057,297	$149,196,042	$ 4,331,920,788
62	Aug 2016	$18,630,683	$94,838,080	$254,478,811	$1,106,795,160	$1,733,998,074	$150,612,214	$823,462,506	$0	$13,056,451	$135,207,131	$ 4,331,079,109
63	Sep 2016	$18,645,991	$94,838,062	$255,761,080	$1,106,857,175	$1,734,721,599	$150,551,479	$824,970,932	$178,296,084	$75,392,846	$135,184,206	$ 4,575,219,454
64	Oct 2016	$18,645,191	$94,854,394	$255,781,321	$1,105,663,404	$1,742,320,494	$150,732,786	$830,951,450	$180,670,728	$78,262,797	$135,859,890	$ 4,593,742,455
65	Nov 2016	$18,652,664	$94,872,989	$255,809,266	$1,105,764,128	$1,742,837,306	$150,762,909	$831,712,903	$184,137,405	$79,474,812	$136,069,850	$ 4,600,094,233
66	Dec 2016	$18,676,991	$94,873,060	$264,612,613	$1,133,695,495	$1,757,159,286	$151,903,903	$815,549,135	$185,286,763	$79,876,649	$138,148,965	$ 4,639,782,859

4) ISO Incentive Plant Activity (See Note 6)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
67	Jan 2016	$0	$0	$101,880	($9,349)	$1,209,250	$1,072,936	($603,133)	$0	$0	$274,785	$2,046,368
68	Feb 2016	$0	$0	($8,631,505)	$16,522,096	$2,191,991	$329,244	$852,598	$0	$0	$299,244	$11,563,667
69	Mar 2016	$9,932,171	$0	$2,080	$60,898	$555,488	$155,258	$318,975	$0	$0	$174,958	$11,199,828
70	Apr 2016	$11,156	$40,960	($2,030,729)	$2,463,489	$1,787,068	$227,930	$578,610	$0	$1,693,868	$279,665	$5,052,017
71	May 2016	$7,352	$457	($54,582)	($161,954)	$924,608	$111,054	$215,647	$0	$344,050	$154,736	$1,541,368
72	Jun 2016	($523,033)	$530,821	$71,058	($105,463)	$2,433,751	($448,179)	$517,712	$0	$1,299	$368,779	$2,846,744
73	Jul 2016	$9,500	$3,532	$4,831	$41,520	$498,325	$95,818	$290,532	$0	$594	$169,986	$1,114,638
74	Aug 2016	($1,271)	$1,656	$253,565	($172,264)	$19,190,528	($178,070)	($5,946,067)	$0	($846)	($13,988,911)	($841,679)
75	Sep 2016	$15,309	($18)	$1,282,269	$62,016	$723,525	($60,735)	$1,508,426	$178,296,084	$62,336,396	($22,925)	$244,140,345
76	Oct 2016	($801)	$16,333	$20,241	($1,193,771)	$7,598,895	$181,307	$5,980,518	$2,374,644	$2,869,951	$675,684	$18,523,001
77	Nov 2016	$7,474	$18,595	$27,945	$100,724	$516,812	$30,123	$761,453	$3,466,677	$1,212,015	$209,960	$6,351,778
78	Dec 2016	$24,326	$71	$8,803,346	$27,931,366	$14,321,981	$1,140,994	($16,163,768)	$1,149,358	$401,837	$2,079,115	$39,688,626
79	Total:	$9,482,184	$612,406	($149,601)	$45,539,309	$51,952,222	$2,657,678	($11,688,497)	$185,286,763	$68,859,162	($9,324,925)	$343,226,702

5) Total Transmission Activity Not Including Incentive Plant Activity (See Note 7):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
80	Jan 2016	-$1,616,115	$21,089	$16,407,229	$13,631,723	$5,896,067	$9,633,800	$9,419,456	$938,443	$1,701,955	-$43,937	$55,989,710
81	Feb 2016	-$1,086	-$4,136	$2,499,653	$6,727,760	$11,131	$10,541,695	$234,003	-$24,970	$103,305	$5,504	$20,092,858
82	Mar 2016	$1,826	$82,797	$14,030,107	$30,133,328	$701,840	$24,995,605	$9,611,159	$27,210	$1,421,895	$8,819,258	$89,825,025
83	Apr 2016	-$1,002	$5,002	$38,592,232	$17,474,341	-$1,263,838	$12,995,693	-$235,406	$2,327,053	$8,269,772	$419,843	$78,583,690
84	May 2016	$1,001	$8,501	$1,171,485	$2,417,028	$2,763,272	$8,549,428	$476,624	$240,024	$1,595,074	$1,010,443	$18,232,880
85	Jun 2016	$1,329	-$936,426	$9,360,356	$50,050,530	-$21,683,708	$18,354,182	$1,648,475	$3,250,929	$24,252,927	$2,941,084	$87,239,677
86	Jul 2016	-$5,716	$4,115	$11,802,138	$85,427,899	-$619,272	$7,829,383	-$798,502	$608,007	$994,761	$353,214	$105,596,027
87	Aug 2016	-$1,795	$18,178	-$1,079,458	$644,993	$1,327,009	$10,297,788	$421,478	$662,022	-$1,128,452	-$20,767	$11,140,997
88	Sep 2016	-$1,404	$2,729,155	$901,209	$5,926,401	$522,499	$10,565,952	$7,614,465	$843,201	$424,848	$9,056	$29,535,383
89	Oct 2016	$0	$101,939	$33,870,422	$26,049,680	$1,300,796	$9,269,649	$1,554,874	-$6,167,404	-$778,271	-$96,872	$65,104,812
90	Nov 2016	$0	$11,216	$6,737,310	$20,887,674	$4,486,087	$10,505,211	-$2,985,080	$4,884,497	-$5,088,933	-$9,991	$39,427,991
91	Dec 2016	$0	$2,180	$4,808,023	$33,624,406	$131,295	$13,401,544	$2,430,588	-$742,546	-$506,036	$2,455,281	$55,604,737
92	Total:	-$1,622,961	$2,043,610	$139,100,705	$292,995,764	-$6,426,822	$146,939,930	$29,392,133	$6,846,465	$31,262,845	$15,842,118	$656,373,787

6) Total Monthly Transmission Activity as a Percent of Annual Transmission Activity (See Note 8)

	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
93	Jan 2016	99.6%	1.0%	11.8%	4.7%	-91.7%	6.6%	32.0%	13.7%	5.4%	-0.3%
94	Feb 2016	0.1%	-0.2%	1.8%	2.3%	-0.2%	7.2%	0.8%	-0.4%	0.3%	0.0%
95	Mar 2016	-0.1%	4.1%	10.1%	10.3%	-10.9%	17.0%	32.7%	0.4%	4.5%	55.7%
96	Apr 2016	0.1%	0.2%	27.7%	6.0%	19.7%	8.8%	-0.8%	34.0%	26.5%	2.7%
97	May 2016	-0.1%	0.4%	0.8%	0.8%	-43.0%	5.8%	1.6%	3.5%	5.1%	6.4%
98	Jun 2016	-0.1%	-45.8%	6.7%	17.1%	337.4%	12.5%	5.6%	47.5%	77.6%	18.6%
99	Jul 2016	0.4%	0.2%	8.5%	29.2%	9.6%	5.3%	-2.7%	8.9%	3.2%	2.2%
100	Aug 2016	0.1%	0.9%	-0.8%	0.2%	-20.6%	7.0%	1.4%	9.7%	-3.6%	-0.1%
101	Sep 2016	0.1%	133.5%	0.6%	2.0%	-8.1%	7.2%	25.9%	12.3%	1.4%	0.1%
102	Oct 2016	0.0%	5.0%	24.3%	8.9%	-20.2%	6.3%	5.3%	-90.1%	-2.5%	-0.6%
103	Nov 2016	0.0%	0.5%	4.8%	7.1%	-69.8%	7.1%	-10.2%	71.3%	-16.3%	-0.1%
104	Dec 2016	0.0%	0.1%	3.5%	11.5%	-2.0%	9.1%	8.3%	-10.8%	-1.6%	15.5%

4) Calculation of change in Non-Incentive ISO Plant:

A) Change in ISO Plant Balance December to December (See Note 9)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
105	$8,869,049	$2,254,447	$61,124,235	$218,998,202	$69,368,470	$13,579,661	-$3,742,391	$185,286,780	$68,939,144	-$5,060,454	$619,617,143

B) Change in Incentive ISO Plant (See Note 10)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
106	$9,482,184	$612,406	-$149,601	$45,539,309	$51,952,222	$2,657,678	-$11,688,497	$185,286,763	$68,859,162	-$9,324,925	$343,226,702

C) Change in Non-Incentive ISO Plant (See Note 11)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
107	-$613,135	$1,642,041	$61,273,836	$173,458,893	$17,416,247	$10,921,983	$7,946,106	$18	$79,982	$4,264,471	$276,390,441

5) Other ISO Transmission Activity without Incentive Plant Activity (See Note 12):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
108	Jan 2016	-$610,549	$16,945	$7,227,381	$8,070,232	-$15,977,937	$716,076	$2,546,532	$2	$4,354	-$11,827	$1,981,210
109	Feb 2016	-$410	-$3,323	$1,101,097	$3,982,958	-$30,163	$783,560	$63,262	$0	$264	$1,482	$5,898,726
110	Mar 2016	$690	$66,528	$6,180,260	$17,839,486	-$1,901,939	$1,857,913	$2,598,358	$0	$3,638	$2,374,017	$29,018,950
111	Apr 2016	-$379	$4,019	$16,999,871	$10,345,132	$3,424,913	$965,964	-$63,642	$6	$21,157	$113,016	$31,810,059
112	May 2016	$378	$6,830	$516,039	$1,430,925	-$7,488,279	$635,475	$128,854	$1	$4,081	$271,997	-$4,493,698
113	Jun 2016	$502	-$752,418	$4,123,235	$29,630,836	$58,761,362	$1,364,259	$445,662	$8	$62,048	$791,697	$94,427,192
114	Jul 2016	-$2,159	$3,306	$5,198,840	$50,574,891	$1,678,185	$581,955	-$215,873	$2	$2,545	$95,080	$57,916,771
115	Aug 2016	-$678	$14,606	-$475,501	$381,848	-$3,596,104	$765,430	$113,946	$2	-$2,887	-$5,590	-$2,804,929
116	Sep 2016	-$530	$2,192,876	$396,982	$3,508,539	-$1,415,937	$785,363	$2,058,556	$2	$1,087	$2,438	$7,529,375
117	Oct 2016	$0	$81,908	$14,919,915	$15,421,891	-$3,525,067	$689,009	$420,357	-$16	-$1,991	-$26,076	$27,979,929
118	Nov 2016	$0	$9,012	$2,967,784	$12,365,888	-$12,156,987	$780,848	-$807,011	$13	-$13,019	-$2,689	$3,143,839
119	Dec 2016	$0	$1,752	$2,117,933	$19,906,268	-$355,800	$996,131	$657,105	-$2	-$1,295	$660,926	$23,983,019
120	Total:	-$613,135	$1,642,041	$61,273,836	$173,458,893	$17,416,247	$10,921,983	$7,946,106	$18	$79,982	$4,264,471	$276,390,441

Notes:

1) Amounts on Line 13 from corresponding account Schedule 7, column 2.
Amounts on Line 1 must match corresponding account Schedule 7, Column 2 for previous year.
The amounts for each month on the remaining lines are calculated by summing the following values:
  a) Other ISO Transmission Activity without Incentive Plant Activity on Lines 108-119 for the same month;
  b) ISO Incentive Plant Activity on Lines 67 to 78 for the same month; and
  c) The previous month balance of the Transmission Plant - ISO amounts on Lines 1-13.
For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:
  a) the "Other ISO Transmission Activity without Incentive Plant Activity" for May of the Prior Year (on Line 112, Column 5);
  b) the "ISO Incentive Plant Activity" for May of the Prior Year (on Line 71, Column 5),
  c) and the "Transmission Plant - ISO" amount for April of the Prior Year (on Line 5, Column 5).

2) Amounts on Line 15 must match 6-Plant Study amounts for Distribution Plant - ISO for previous year.
  Amounts on Line 16 must match amounts on 6-PlantStudy for Distribution Plant - ISO.

3) Reconciles to BOY and EOY FERC Form 1 (FF1 207, Lines 48-56 , Column g).

4) Includes recorded Transmission Plant-In-Service additions, retirements, transfers and adjustments. From SCE internal acounting records.

5) Includes balances for SCE Incentive Projects.

6) Monthly differences from previous matrix. Other columns from SCE internal accounting records.

7) Amount in matrix on lines 41 to 52 minus amount in matrix on lines 67 to 78

8) Amount in "Total Transmission Activity Not Including Incentive Plant Activity" matrix divided by Total on Line 92 for each account/month.

9) Amount on Line 13 less amount on Line 1 for each account.

10) Line 79

11) Amount on Line 105 less amount on Line 106 for each account.

12) For each column (FERC Account) divide Line 107 by Line 92 to arrive at a ratio for each column.
  Apply the ratio of each column to each monthly value from Lines 80-91 to calculate the values for
  the corresponsing months listed in Lines 108-119.

Transmission Plant Study

Input cells are shaded yellow

A) Plant Classified as Transmission in FERC Form 1 for Prior Year:

Prior Year: 2016

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	**Substation**					
3	352	$825,778,508	FF1 207.49g	$531,582,611	64.37%	
4	353	$5,586,246,880	FF1 207.50g	$3,249,175,449	58.16%	
5	**Total Substation**	$6,412,025,388	L 3 + L 4	$3,780,758,060	58.96%	
6						
7	**Land**					
8	350	$338,945,967	FF1 207.48g	$252,172,630	74.40%	
9						
10	**Total Substation and Land**	$6,750,971,355	L 5 + L 8	$4,032,930,690	59.74%	
11						
12	**Lines**					
13	354	$2,305,498,226	FF1 207.51g	$2,233,991,232	96.90%	
14	355	$1,158,164,968	FF1 207.52g	$324,258,228	28.00%	
15	356	$1,499,811,260	FF1 207.53g	$1,235,903,790	82.40%	
16	357	$253,220,290	FF1 207.54g	$185,508,197	73.26%	
17	358	$368,734,329	FF1 207.55g	$81,951,072	22.22%	
18	359	$200,535,234	FF1 207.56g	$182,027,087	90.77%	
19	**Total Lines**	$5,785,964,307	Sum L13 to L18	$4,243,639,605	73.34%	
20						
21	**Total Transmission**	**$12,536,935,662**	L 10 + L 19	**$8,276,570,295**	**66.02%**	Note 1

B) Plant Classified as Distribution in FERC Form 1:

Line	Account	Total Plant	Data Source	Distribution Plant - ISO	ISO % of Total	
22						
23	**Land:**					
24	360	$124,672,241	FF1 207.60g	$0	0.00%	
25	**Structures:**					
26	361	$611,762,558	FF1 207.61g	$0	0.00%	
27	362	$2,397,308,356	FF1 207.62g	$0	0.00%	
28	**Total Structures**	$3,009,070,914	L 26 + L 27	$0	0.00%	
29						
30	**Total Distribution**	**$3,133,743,155**	L 24 + L 28	**$0**	**0.00%**	Note 2

Notes:

1) Total transmission does not include account 359.1 "Asset Retirement Costs for Transmission Plant"
Total on this line is also equal to FF1 207.58g (Total Transmission Plant)
less FF1 207.57g (Asset Retirement Costs for Transmission Plant).

2) Only accounts 360-362 included as there is no ISO plant in any other Distribution accounts.

Instructions:

1) Perform annual Transmission Study pursuant to instructions in tariff.
2) Enter total amounts of plant from FERC Form 1 in Column 1, "Total Plant".
3) Enter ISO portion of plant in Column 2, "Transmission Plant - ISO, or "Distribution Plant - ISO".

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Prior Year: 2016

Balances for Transmission Depreciation Reserve - ISO during the Prior Year, including December of previous year (See Note 1):

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												=Sum C2 to C11
		FERC Account:										
Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	Dec 2015	$0	$15,448,963	$62,849,697	$372,512,031	$406,863,964	$46,334,041	$386,000,140	$132,074	$1,627,345	$13,852,616	$1,305,620,870
2	Jan 2016	$0	$15,673,665	$63,472,377	$378,290,251	$406,578,952	$46,502,639	$383,943,844	$126,507	$1,673,997	$14,100,949	$1,310,363,181
3	Feb 2016	$0	$15,899,445	$64,437,002	$384,317,477	$410,941,475	$46,603,053	$386,970,194	$126,968	$1,716,259	$14,343,863	$1,325,355,736
4	Mar 2016	$0	$16,121,590	$65,115,015	$389,598,989	$414,759,392	$45,534,270	$384,815,192	$127,102	$1,762,154	$13,560,314	$1,331,394,017
5	Apr 2016	$0	$16,347,075	$65,230,085	$395,343,496	$420,136,965	$45,445,159	$388,110,773	$112,846	$1,826,924	$13,758,660	$1,346,311,983
6	May 2016	$0	$16,572,477	$66,255,038	$401,621,252	$422,324,240	$45,720,412	$391,014,055	$111,649	$1,878,839	$13,888,708	$1,359,386,668
7	Jun 2016	$0	$16,837,350	$67,088,882	$406,298,099	$443,929,530	$45,202,518	$393,270,413	$91,613	$1,994,290	$13,794,380	$1,388,507,075
8	Jul 2016	$0	$17,062,639	$67,874,430	$409,844,784	$448,916,460	$45,541,270	$396,881,907	$88,113	$2,045,879	$14,003,062	$1,402,258,543
9	Aug 2016	$0	$17,287,349	$68,973,301	$416,349,764	$452,360,839	$45,681,841	$399,819,187	$84,275	$2,091,628	$14,255,660	$1,416,903,845
10	Sep 2016	$0	$17,398,869	$70,025,235	$422,677,384	$456,476,381	$45,802,453	$398,765,369	$79,304	$2,141,645	$14,486,591	$1,427,853,230
11	Oct 2016	$0	$17,623,137	$70,307,365	$428,334,928	$459,971,896	$46,030,447	$401,070,351	$363,354	$2,389,386	$14,729,836	$1,440,820,701
12	Nov 2016	$0	$17,851,330	$71,257,987	$434,195,531	$460,943,909	$46,160,865	$405,901,284	$581,519	$2,634,501	$14,963,804	$1,454,490,730
13	Dec 2016	$0	$18,079,939	$72,260,283	$439,653,028	$465,353,602	$46,058,792	$407,738,326	$839,659	$2,896,108	$14,910,822	$1,467,790,558
14	13-Mo. Avg:	$0	$16,784,910	$67,318,977	$406,079,770	$436,119,816	$45,893,674	$394,177,003	$220,383	$2,052,227	$14,203,790	$1,382,850,549

2) Distribution Depreciation Reserve - ISO (See Note 2)

	Col 1	Col 2	Col 3	Col 4	Col 5	
		FERC Account:			=Sum C2 to C4	
	Mo/YR	360	361	362	Total	Notes
15	Dec 2015	$0	$0	$0	$0	Beginning of Year ("BOY") amount
16	Dec 2016	$0	$0	$0	$0	End of Year ("EOY") amount
17	BOY/EOY Average:	$0	$0	$0	$0	Average of Line 15 and Line 16

3) General and Intangible Depreciation Reserve

	Col 1	Col 2	Col 3	Col 4	Col 5	
			=C4+C5			
	Mo/YR		Total Gen. and Int. Depreciation Reserve	General Depreciation Reserve	Intangible Depreciation Reserve	Source
18	Dec 2015	BOY:	$1,958,254,795	$1,011,263,915	$946,990,880	FF1 219.28c and 200.21c for previous year
19	Dec 2016	EOY:	$1,917,414,678	$1,073,416,375	$843,998,303	FF1 219.28c and 200.21c
20		BOY/EOY Average:	$1,937,834,737			Average of Line 18 and Line 19

a) Average BOY/EOY General and Intangible Depreciation Reserve

		Amount	Source
21	Total G+I Dep. Reserve on Average BOY/EOY basis:	$1,937,834,737	Line 20
22	Transmission W&S Allocation Factor:	6.1650%	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$119,467,537	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

		Amount	Source
24	Total G+I Dep. Reserve on Average EOY basis:	$1,917,414,678	Line 19
25	Transmission W&S Allocation Factor:	6.1650%	27-Allocators, Line 9
26	G + I Plant Dep. Reserve (EOY):	$118,208,640	Line 24 * Line 25

Transmission Activity Used to Determine Monthly Transmission Depreciation Reserve - ISO Balances

1) ISO Depreciation Expense (See Note 3)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
27	Jan 2016	$0	$225,584	$1,007,565	$6,237,115	$4,401,400	$950,159	$3,150,767	$304	$41,963	$243,214	$16,258,071
28	Feb 2016	$0	$225,607	$1,023,262	$6,253,707	$4,371,370	$955,630	$3,155,707	$304	$41,978	$243,556	$16,271,120
29	Mar 2016	$0	$225,602	$1,007,134	$6,295,913	$4,375,766	$959,033	$3,158,035	$304	$41,978	$243,947	$16,307,713
30	Apr 2016	$0	$225,694	$1,020,375	$6,332,758	$4,373,028	$965,190	$3,165,450	$304	$41,990	$247,260	$16,372,050
31	May 2016	$0	$225,757	$1,052,434	$6,359,122	$4,383,626	$968,842	$3,166,758	$304	$47,521	$247,771	$16,452,135
32	Jun 2016	$0	$225,767	$1,053,422	$6,361,734	$4,370,279	$971,125	$3,167,634	$304	$48,644	$248,325	$16,447,235
33	Jul 2016	$0	$225,460	$1,062,405	$6,422,507	$4,494,710	$973,926	$3,170,083	$304	$48,848	$249,834	$16,648,078
34	Aug 2016	$0	$225,470	$1,073,549	$6,526,693	$4,499,135	$975,999	$3,170,272	$304	$48,858	$250,179	$16,770,460
35	Sep 2016	$0	$225,492	$1,073,074	$6,527,124	$4,530,844	$977,796	$3,155,449	$304	$48,846	$231,986	$16,770,915
36	Oct 2016	$0	$228,526	$1,076,670	$6,534,474	$4,529,436	$980,012	$3,164,515	$245,462	$249,885	$231,959	$17,240,938
37	Nov 2016	$0	$228,662	$1,108,667	$6,563,760	$4,537,719	$982,673	$3,180,784	$248,727	$259,134	$232,804	$17,342,930
38	Dec 2016	$0	$228,700	$1,115,083	$6,589,420	$4,514,051	$985,154	$3,180,668	$253,493	$263,000	$233,073	$17,362,643
39	Total:	$0	$2,716,320	$12,673,640	$77,004,328	$53,381,363	$11,645,539	$37,986,122	$750,422	$1,182,645	$2,903,907	$200,244,286

2) Total Transmission Allocation Factors (See Note 4)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
40	Jan 2016	99.6%	1.0%	11.8%	4.7%	-91.7%	6.6%	32.0%	13.7%	5.4%	-0.3%
41	Feb 2016	0.1%	-0.2%	1.8%	2.3%	-0.2%	7.2%	0.8%	-0.4%	0.3%	0.0%
42	Mar 2016	-0.1%	4.1%	10.1%	10.3%	-10.9%	17.0%	32.7%	0.4%	4.5%	55.7%
43	Apr 2016	0.1%	0.2%	27.7%	6.0%	19.7%	8.8%	-0.8%	34.0%	26.5%	2.7%
44	May 2016	-0.1%	0.4%	0.8%	0.8%	-43.0%	5.8%	1.6%	3.5%	5.1%	6.4%
45	Jun 2016	-0.1%	-45.8%	6.7%	17.1%	337.4%	12.5%	5.6%	47.5%	77.6%	18.6%
46	Jul 2016	0.4%	0.2%	8.5%	29.2%	9.6%	5.3%	-2.7%	8.9%	3.2%	2.2%
47	Aug 2016	0.1%	0.9%	-0.8%	0.2%	-20.6%	7.0%	1.4%	9.7%	-3.6%	-0.1%
48	Sep 2016	0.1%	133.5%	0.6%	2.0%	-8.1%	7.2%	25.9%	12.3%	1.4%	0.1%
49	Oct 2016	0.0%	5.0%	24.3%	8.9%	-20.2%	6.3%	5.3%	-90.1%	-2.5%	-0.6%
50	Nov 2016	0.0%	0.5%	4.8%	7.1%	-69.8%	7.1%	-10.2%	71.3%	-16.3%	-0.1%
51	Dec 2016	0.0%	0.1%	3.5%	11.5%	-2.0%	9.1%	8.3%	-10.8%	-1.6%	15.5%

3) Calculation of Non-Incentive ISO Reserve

A) Change in Depreciation Reserve - ISO (See Note 5)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
52	$0	$2,630,976	$9,410,586	$67,140,997	$58,489,638	-$275,249	$21,738,186	$707,584	$1,268,763	$1,058,206	$162,169,688

B) Total Depreciation Expense (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
53	$0	$2,716,320	$12,673,640	$77,004,328	$53,381,363	$11,645,539	$37,986,122	$750,422	$1,182,645	$2,903,907	$200,244,286

C) Other Activity (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	$0	-$85,344	-$3,263,054	-$9,863,331	$5,108,275	-$11,920,788	-$16,247,936	-$42,837	$86,118	-$1,845,701	-$38,074,599

4) Other Transmission Activity (See Note 8)

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
												Sum C2 - C11
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
55	Jan 2016	$0	-$881	-$384,884	-$458,895	-$4,686,411	-$781,561	-$5,207,064	-$5,872	$4,688	$5,119	-$11,515,760
56	Feb 2016	$0	$173	-$58,637	-$226,482	-$8,847	-$855,216	-$129,356	$156	$285	-$641	-$1,278,566
57	Mar 2016	$0	-$3,458	-$329,121	-$1,014,400	-$557,848	-$2,027,817	-$5,313,037	-$170	$3,917	-$1,027,496	-$10,269,431
58	Apr 2016	$0	-$209	-$905,305	-$588,252	$1,004,545	-$1,054,301	$130,132	-$14,560	$22,780	-$48,914	-$1,454,083
59	May 2016	$0	-$355	-$27,481	-$81,366	-$2,196,351	-$693,589	-$263,477	-$1,502	$4,394	-$117,723	-$3,377,450
60	Jun 2016	$0	$39,106	-$219,577	-$1,684,888	$17,235,011	-$1,489,019	-$911,275	-$20,341	$66,808	-$342,654	$12,673,171
61	Jul 2016	$0	-$172	-$276,857	-$2,875,822	$492,220	-$635,174	$441,411	-$3,804	$2,740	-$41,152	-$2,896,609
62	Aug 2016	$0	-$759	$25,322	-$21,713	-$1,054,756	-$835,428	-$232,993	-$4,142	-$3,108	$2,419	-$2,125,158
63	Sep 2016	$0	-$113,973	-$21,141	-$199,505	-$415,302	-$857,183	-$4,209,267	-$5,276	$1,170	-$1,055	-$5,821,531
64	Oct 2016	$0	-$4,257	-$794,540	-$876,929	-$1,033,920	-$752,018	-$859,532	$38,589	-$2,144	$11,286	-$4,273,466
65	Nov 2016	$0	-$468	-$158,045	-$703,157	-$3,565,707	-$852,256	$1,650,149	-$30,562	-$14,018	$1,164	-$3,672,900
66	Dec 2016	$0	-$91	-$112,788	-$1,131,923	-$104,358	-$1,087,226	-$1,343,626	$4,646	-$1,394	-$286,055	-$4,062,815
67	Total:	$0	-$85,344	-$3,263,054	-$9,863,331	$5,108,275	-$11,920,788	-$16,247,936	-$42,837	$86,118	-$1,845,701	-$38,074,599

Notes:

1) Amounts on Line 13 based on current year Plant Study. Amounts on Line 1 shall be based on previous year Plant Study, and shall match amounts on Line 13 in previous year Annual Update.

The amounts for each month on the remaining lines are calculated by summing the following values:

a) Depreciation Expense (on Lines 27 to 38) for the same month;

b) Other Transmission Activity (on Lines 55 to 66) for the same month; and

c) Balances for Transmission Depreciation Reserve (on Lines 1 to 13) for the previous month.

For instance, the amount for May of the Prior Year (on Line 6) for Account 353 (Column 5) is the sum of the following values:

a) Depreciation Expense for May of the Prior Year (on Line 44, Column 5);

b) Other Transmission Activity for May of the Prior Year (on Line 59, Column 5); and

c) The balances for Transmission Depreciation Reserve for April of the Prior Year (on Line 5, column 5).

2) Amounts on Line 15 derived from Plant Study for previous year Prior Year.
Amounts on Line 16 derived from Plant Study for Prior Year.

3) From 17-Depreciation, Lines 24 to 35.

4) From 6-PlantInService, Lines 93 to 104.

5) Line 13 - Line 1.

6) Line 39.

7) Line 52 - Line 53.

8) Multiply the montly "Total Transmission Allocation Factors" ratios found in Lines 40-51 by the "Other Activity" on Line 54.

Accumulated Deferred Income Taxes

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes

a) End of Year Accumulated Deferred Income Taxes

Line	Account (Col 1)	Total ADIT (Col 2)	Source
1	Account 190	$13,441,450	Line 353, Col. 2
2	Account 282	-$1,533,846,891	Line 452, Col. 2
3	Account 283	-$30,203,164	Line 803, Col. 2
4	Total Accumulated Deferred Income Taxes	-$1,550,608,605	Sum of Lines 1 to 3
5			
6	**b) Beginning of Year Accumulated Deferred Income Taxes**		
7		**BOY**	
8		**ADIT**	**Source**
9	Total Accumulated Deferred Income Taxes	-$1,310,937,724	Previous Year Informational Filing, Line 4, Col. 2
10			
11	**c) Average of Beginning and End of Year Accumulated Deferred Income Taxes**		
12		**Average**	
13		**ADIT**	**Source**
14	Weighted Average ADIT:	-$1,384,321,610	Line 819

2) Account 190 Detail

	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
100	190.000	Amort of Debt Issuance Cost	$888,877	$729		$888,148		C: Relates to all Regulated Electric Property
101	190.000	Executive Incentive Comp	$4,269,587	$11,388			$4,258,199	C: Relates to employees in all functions
102	190.000	Bond Discount Amort	$1,094,107	$897		$1,093,210		C: Relates to all Regulated Electric Property
103	190.000	Executive Incentive Plan	$3,098,046	$8,263			$3,089,783	C: Relates to employees in all functions
104	190.000	Ins - Inj/Damages Prov	$45,946,549	$122,551			$45,823,998	C: Relates to employees in all functions
105	190.000	Accrued Vacation	$18,594,295	$49,596			$18,544,699	C: Relates to employees in all functions
106	190.000	PBOP 401H Amortization	$53,413,524	$142,467			$53,271,057	C: Relates to employees in all functions
107	190.000	EMS	$1,263,638	$1,036		$1,262,602		C: Relates to all Regulated Electric Property
108	190.000	Amortization of Debt Expense	$1,564,283	$1,282		$1,563,001		C: Relates to all Regulated Electric Property
109	190.000	Decommissioning	$369,377,416	$369,377,416				Relates to Nuclear Decommissioning Costs
110	190.000	Balancing Accounts	$238,433	$238,433				Relates Entirely to CPUC Balancing Account Recovery
111	190.000	CIAC/ITCC	$85,326,766	$85,326,766				Non-Rate Base FAS 109 Tax - CIAC
112	190.000	Pension & PBOP	$16,661,615	$44,441			$16,617,174	C: Relates to employees in all functions
113	190.000	Property/Non-ISO	$9,929,442	$9,929,442				Non-Rate Base Property
114	190.000	Regulatory Assets/Liab	$11,348,185	$11,348,185				Relates to Nonrecovery Balancing Account
115	190.000	Temp - Other/Non-ISO	$274,818,699	$274,818,699				Not Component of Rate Base
116	190.000	Net Operating Losses DTA	$19,586,959	$0		$19,586,959		NOL/DTA

Continuation of Account 190 Detail

	ACCT 190	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
117	…							
								Source
250		Total Electric 190	$917,420,421	$751,421,589	$0	$24,393,921	$141,604,911	Sum of Above Lines beginning on Line 100

Account 190 Gas and Other Income: (Instructions 1&2)

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
300	190.000	Balancing Accounts	$4,384,411					Gas and Other Non-ISO Related Costs
301	…							

Line	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
350	Total Account 190 Gas and Other Income	$4,384,411	$0	$0	$0	$0	Sum of Above Lines beginning on Line 300
351	Total Account 190	$921,804,832	$751,421,589	$0	$24,393,921	$141,604,911	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				19.314%	6.165%	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	$13,441,450		$0	$4,711,505	$8,729,945	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
354	FERC Form 1 Account 190	$921,804,832	Must match amount on Line 351, Col. 2				FF1 234.18c

3) Account 282 Detail

Line	ACCT 282	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
400	282.000	Fully Normalized Deferred Tax	-$1,533,846,891		-$1,533,846,891			Property-Related FERC Costs
401	282.000	Property/Non-ISO	-$8,737,861,331	-$8,737,861,331				Property-Related CPUC Costs
402	282.000	Temp - Other/Non-ISO	$0	$0				Not Component of Rate Base
403	282.000	Capitalized software	-$9,484,309	-$9,484,309				Property-Related CPUC Costs - Cap Software
404	282.000	Audit Rollforward	-$4,223,920	-$4,223,920				Property-Related CPUC Costs - Audit
405	282.000	Property/Non-ISO	-$11,553,647	-$11,553,647				Gas and Other Non-ISO Related Costs
406	…							

Line	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
450	Total Account 282	-$10,296,970,098	-$8,763,123,207	-$1,533,846,891	$0	$0	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)				19.314%	6.165%	27-Allocators Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)	-$1,533,846,891		-$1,533,846,891	$0	$0	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282	-$10,296,970,098	Must match amount on Line 450, Col. 2				FF1 275.5k

4) Account 283 Detail

	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric:							
500	283.000	Ad Valorem Lien Date Adj-Electric	-$91,617,729			-$91,617,729		Relates to all Regulated Electric Property
501	283.000	Refunding & Retirement of Debt	-$63,685,749	-$52,200		-$63,633,549		C: Relates to all Regulated Electric Property
502	283.000	Health Care - IBNR	-$3,537,910	-$9,436			-$3,528,474	C: Relates to employees in all functions
503	283.000	Balancing Accounts	-$133,742,405	-$133,742,405				Relates Entirely to CPUC Balancing Account Recovery
504	283.000	Capitalized Software	$0	$0				Property-Related CPUC Costs - Cap Software
505	283.000	Decommissioning	-$348,213,647	-$348,213,647				Relates to Nuclear Decommissioning Costs
506	283.000	Property/Non-ISO	$0	$0				Property-Related CPUC Costs
507	283.000	Regulatory Assets/Liab	$0	$0				Relates Entirely to CPUC Balancing Account Recovery
508	283.000	Temp - Other/Non-ISO	-$25,131,601	-$25,131,601				Non-Rate Base FAS 109 Tax Flow-Thru

Continuation of Account 283 Detail

	ACCT 283	Col 1 DESCRIPTION	Col 2 END BAL per G/L	Col 3 Gas, Generation or Other Related	Col 4 ISO Only	Col 5 Plant Related	Col 6 Labor Related	Col 7 (Instructions 1&2) Description
	Electric (continued):							
509	…							
650		Total Electric 283	-$665,929,040	-$507,149,289	$0	-$155,251,278	-$3,528,474	Sum of Above Lines beginning on Line 500

	Account 283 Gas and Other:	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
700	283.000	Temp - Other/Non-ISO	-$303,719	-$303,719				Gas and Other Non-ISO Related Costs
701	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
800	Total Account 283 Gas and Other	-$303,719	-$303,719	$0	$0	$0	Sum of Above Lines beginning on Line 700
801	Total Account 283	-$666,232,759	-$507,453,008	$0	-$155,251,278	-$3,528,474	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				19.314%	6.165%	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	-$30,203,164		$0	-$29,985,633	-$217,530	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	-$666,232,759	Must match amount on Line 801, Col. 2				FF1 277.19k

5) Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 922404; 201717008

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
		See Note 1	See Note 2			Col 5 / Tot. Days	= Col 2 * Col 6	See Note 3
	Future Test Period	Mthly Deferred Tax Amount	Deferred Tax Balance	Days in Month	Number of Days Left in Period	Prorata Percentages	Monthly Prorata Amounts	Annual Accumulated Prorata Calculation
805	Beginning Deferred Tax Balance (Line 9, Col. 2)		-$1,310,937,724		366	100.00%		-$1,310,937,724
806	January	-$19,972,573.43	-$1,330,910,297	31	335	91.53%	-$18,280,907	-$1,329,218,631
807	February	-$19,972,573.43	-$1,350,882,871	29	306	83.61%	-$16,698,381	-$1,345,917,012
808	March	-$19,972,573.43	-$1,370,855,444	31	275	75.14%	-$15,006,715	-$1,360,923,727
809	April	-$19,972,573.43	-$1,390,828,018	30	245	66.94%	-$13,369,619	-$1,374,293,346
810	May	-$19,972,573.43	-$1,410,800,591	31	214	58.47%	-$11,677,953	-$1,385,971,299
811	June	-$19,972,573.43	-$1,430,773,165	30	184	50.27%	-$10,040,857	-$1,396,012,156
812	July	-$19,972,573.43	-$1,450,745,738	31	153	41.80%	-$8,349,191	-$1,404,361,346
813	August	-$19,972,573.43	-$1,470,718,311	31	122	33.33%	-$6,657,524	-$1,411,018,871
814	September	-$19,972,573.43	-$1,490,690,885	30	92	25.14%	-$5,020,428	-$1,416,039,299
815	October	-$19,972,573.43	-$1,510,663,458	31	61	16.67%	-$3,328,762	-$1,419,368,061
816	November	-$19,972,573.43	-$1,530,636,032	30	31	8.47%	-$1,691,666	-$1,421,059,727
817	December	-$19,972,573.43	-$1,550,608,605	31	0	0.00%	$0	-$1,421,059,727
818	Ending Balance (Line 4, Col. 2)		-$1,550,608,605					
819						Weighted Average ADIT Balance:		-$1,384,321,610

Instruction 1: For any "Company Wide" ADIT line item balance (i.e., that include Catalina Gas or Water costs), indicate in Column 7 with a leading "C:".

Instruction 2: For any Company Wide ADIT balance items, include a portion of the total Column 2 balance in Column 3 "Gas, Generation, or Other Related" based on the following percentages.

1) For Line items allocated based on the Wages and Salaries Allocation Factor:

	FERC Form 1 Reference or Instruction	**Prior Year Value**
A:Total Electric Wages and Salaries	FF1 354.28b	$737,797,550
B:Gas Wages and Salaries	FF1 355.62b	$609,829
C:Water Wages and Salaries	FF1 355.64b	$1,363,321
D:Total Electric, Gas, and Water Wages and Salaries	A+B+C	$739,770,700
E:Labor Percentage "Gas, Generation, or Other"	(B+C) / D	0.2667%

2) For Line items allocated based on the Transmission Plant Allocation Factor or "ISO Only":

	FERC Form 1 Reference or Instruction	**Prior Year Value**
F:Total Electric Plant In Service	FF1 207.104g	$44,298,088,225
G:Total Gas Plant In Service	FF1 201.8d	$5,156,153
H:Total Water Plant in Service	FF1 201.8e	$31,182,471
I:Total Electric, Gas, and Water Plant In Service	F+G+H	$44,334,426,849
J:Plant Percentage "Gas, Generation, or Other"	(G+H) / I	0.0820%

Instruction 3: Classify any ADIT line items relating to refunding and retirement of debt as Plant related (Column 5).

Notes:

1) The monthly deferred tax amounts are equal to the ending ADIT balance minus the beginning ADIT balance, divided by 12 months.
2) For January through December = previous month balance plus amount in Column 2.
3) The weighted average ADIT Balance is equal to the summation of Col. 8, Lines 805 through 817, divided by 13 months.

Prior Year CWIP and Forecast Period Incremental CWIP by Project

Prior Year CWIP is the amount of Construction Work In Progress for projects that have received Commission approval to include CWIP in Rate Base.

1) Prior Year CWIP, Total and by Project

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6
			= Sum of all columns					
Line	Month	Year	Monthly Total CWIP	Tehachapi	Devers to Colorado River	South of Kramer	West of Devers	Red Bluff
1	December	2015	$296,606,973	$225,689,500	$0	$2,844,116	$52,084,176	$9,220,094
2	January	2016	$296,679,130	$234,537,306	$0	$2,844,116	$52,498,624	$0
3	February	2016	$309,317,596	$246,277,835	$0	$2,844,116	$52,874,292	$0
4	March	2016	$316,026,673	$249,130,156	$0	$2,902,846	$53,618,763	$0
5	April	2016	$336,604,184	$264,263,823	$0	$3,081,401	$54,251,603	$0
6	May	2016	$345,602,500	$272,082,292	$0	$3,292,807	$54,675,188	$0
7	June	2016	$355,825,957	$281,130,584	$0	$3,401,902	$55,165,591	$0
8	July	2016	$367,260,330	$288,522,861	$0	$3,505,384	$55,846,692	$0
9	August	2016	$378,773,233	$297,512,902	$0	$3,578,266	$56,943,644	$0
10	September	2016	$143,859,740	$61,004,683	$0	$3,745,751	$57,634,501	$0
11	October	2016	$135,182,377	$48,827,981	$0	$3,889,872	$58,274,960	$0
12	November	2016	$137,652,282	$49,593,830	$0	$3,997,682	$58,866,561	$0
13	December	2016	$115,749,706	$14,915,548	$0	$4,204,927	$69,685,245	$0
14	13 Month Averages:		$271,933,898	$194,883,792	$0	$3,394,860	$56,339,988	$709,238

			Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
Line	Month	Year	Whirlwind Substation Expansion	Colorado River Substation Expansion				
15	December	2015	$6,769,087	$0				
16	January	2016	$6,799,085	$0				
17	February	2016	$7,321,353	$0				
18	March	2016	$10,374,908	$0				
19	April	2016	$15,007,357	$0				
20	May	2016	$15,552,213	$0				
21	June	2016	$16,127,880	$0				
22	July	2016	$19,385,392	$0				
23	August	2016	$20,738,420	$0				
24	September	2016	$21,474,805	$0				
25	October	2016	$24,189,564	$0				
26	November	2016	$25,194,210	$0				
27	December	2016	$26,943,987	$0				
28	13 Month Averages:		$16,606,020	$0	$0	$0	---	---

2) Total Forecast Period CWIP Expenditures (see Note 1)

Line	Month	Year	Col 1 See Note 2 Forecast Expenditures	Col 2 See Note 2 Corporate Overheads	Col 3 See Note 2 Total CWIP Exp	Col 4 See Note 2 Unloaded Total Plant Adds	Col 5 See Note 2 Prior Period CWIP Closed	Col 6 See Note 2 Over Heads Closed to PIS	Col 7 See Note 2 Forecast Period CWIP	Col 8 See Note 2 Forecast Period Incremental CWIP
29	December	2016	---	---	---	---	---	---	$115,749,706	---
30	January	2017	$1,394,374	$104,578	$1,498,952	$1,056,402	$908,847	$11,067	$116,181,189	$431,483
31	February	2017	$3,048,156	$228,612	$3,276,768	$1,350,043	$0	$101,253	$118,006,660	$2,256,954
32	March	2017	$7,375,954	$553,197	$7,929,151	$1,328,768	$0	$99,658	$124,507,386	$8,757,679
33	April	2017	$2,317,450	$173,809	$2,491,259	$32,542,040	$26,336,913	$465,385	$93,991,221	-$21,758,485
34	May	2017	$2,567,144	$192,536	$2,759,680	$936,909	$0	$70,268	$95,743,724	-$20,005,983
35	June	2017	$9,490,637	$711,798	$10,202,435	$23,124,446	$14,613,775	$638,300	$82,183,413	-$33,566,294
36	July	2017	$5,765,727	$432,430	$6,198,157	$2,155,272	$0	$161,645	$86,064,652	-$29,685,054
37	August	2017	$5,784,251	$433,819	$6,218,070	$1,484,272	$0	$111,320	$90,687,129	-$25,062,577
38	September	2017	$6,986,239	$523,968	$7,510,206	$1,798,476	$0	$134,886	$96,263,975	-$19,485,732
39	October	2017	$6,230,831	$467,312	$6,698,144	$1,172,272	$0	$87,920	$101,701,925	-$14,047,781
40	November	2017	$4,951,973	$371,398	$5,323,371	$853,384	$0	$64,004	$106,107,909	-$9,641,798
41	December	2017	$13,053,864	$979,040	$14,032,904	$4,713,015	$0	$353,476	$115,074,321	-$675,385
42	January	2018	$8,546,000	$640,950	$9,186,950	$0	$0	$0	$124,261,271	$8,511,565
43	February	2018	$8,746,000	$655,950	$9,401,950	$0	$0	$0	$133,663,221	$17,913,515
44	March	2018	$21,116,000	$1,583,700	$22,699,700	$0	$0	$0	$156,362,921	$40,613,215
45	April	2018	$21,116,000	$1,583,700	$22,699,700	$0	$0	$0	$179,062,621	$63,312,915
46	May	2018	$21,271,000	$1,595,325	$22,866,325	$0	$0	$0	$201,928,946	$86,179,240
47	June	2018	$21,310,000	$1,598,250	$22,908,250	$0	$0	$0	$224,837,196	$109,087,490
48	July	2018	$21,515,000	$1,613,625	$23,128,625	$0	$0	$0	$247,965,821	$132,216,115
49	August	2018	$21,568,000	$1,617,600	$23,185,600	$0	$0	$0	$271,151,421	$155,401,715
50	September	2018	$23,436,000	$1,757,700	$25,193,700	$0	$0	$0	$296,345,121	$180,595,415
51	October	2018	$28,927,000	$2,169,525	$31,096,525	$0	$0	$0	$327,441,646	$211,691,940
52	November	2018	$22,524,000	$1,689,300	$24,213,300	$0	$0	$0	$351,654,946	$235,905,240
53	December	2018	$22,639,000	$1,697,925	$24,336,925	$0	$0	$0	$375,991,871	$260,242,165
54	**13-Month Averages:**									**$115,461,165**

3) Forecast Period CWIP Expenditures by Project (see Note 1)

3a) Project: Tehachapi

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 = C1 * 16-Plnt Add Line 74 Corporate Overheads	Col 3 = C1 + C2 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 = (C4 - C5) * 16-Plnt Add Line 74 Over Heads Closed to PIS	Col 7 = Prior Month C7 + C3 - C4 - C6 Forecast Period CWIP	Col 8 = C7 - Dec Prior Year C7 Forecast Period Incremental CWIP
55	December	2016	---	---	---	---	---	---	$14,915,548	---
56	January	2017	$623,335	$46,750	$670,085	$1,391,483	$908,847	$36,198	$14,157,951	-$757,596
57	February	2017	$1,344,282	$100,821	$1,445,103	$1,315,973	$0	$98,698	$14,188,383	-$727,164
58	March	2017	$1,233,135	$92,485	$1,325,620	$1,228,278	$0	$92,121	$14,193,605	-$721,943
59	April	2017	$596,909	$44,768	$641,677	$566,909	$0	$42,518	$14,225,855	-$689,693
60	May	2017	$911,909	$68,393	$980,302	$736,909	$0	$55,268	$14,413,980	-$501,568
61	June	2017	$7,874,153	$590,561	$8,464,715	$22,259,718	$14,006,701	$618,976	$0	-$14,915,548
62	July	2017	$2,035,340	$152,651	$2,187,991	$2,035,340	$0	$152,651	$0	-$14,915,548
63	August	2017	$1,470,340	$110,276	$1,580,616	$1,470,340	$0	$110,276	$0	-$14,915,548
64	September	2017	$1,786,543	$133,991	$1,920,534	$1,786,543	$0	$133,991	$0	-$14,915,548
65	October	2017	$1,160,340	$87,026	$1,247,366	$1,160,340	$0	$87,026	$0	-$14,915,548
66	November	2017	$841,452	$63,109	$904,561	$841,452	$0	$63,109	$0	-$14,915,548
67	December	2017	$4,701,083	$352,581	$5,053,664	$4,701,083	$0	$352,581	$0	-$14,915,548
68	January	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
69	February	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
70	March	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
71	April	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
72	May	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
73	June	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
74	July	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
75	August	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
76	September	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
77	October	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
78	November	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
79	December	2018	$0	$0	$0	$0	$0	$0	$0	-$14,915,548
80	**13-Month Averages:**									**-$14,915,548**

3b) Project: Devers to Colorado River

Line	Month	Year	Col 1 Forecast Expenditures	Col 2 = C1 * 16-Plnt Add Line 74 Corporate Overheads	Col 3 = C1 + C2 Total CWIP Exp	Col 4 Unloaded Total Plant Adds	Col 5 Prior Period CWIP Closed	Col 6 = (C4 - C5) * 16-Plnt Add Line 74 Over Heads Closed to PIS	Col 7 = Prior Month C7 + C3 - C4 - C6 Forecast Period CWIP	Col 8 = C7 - Dec Prior Year C7 Forecast Period Incremental CWIP
81	December	2016	---	---	---	---	---	---	$0	---
82	January	2017	$0	$0	$0	$0	$0	$0	$0	$0
83	February	2017	-$80,270	-$6,020	-$86,290	-$80,270	$0	-$6,020	$0	$0
84	March	2017	-$18	-$1	-$19	-$18	$0	-$1	$0	$0
85	April	2017	$0	$0	$0	$0	$0	$0	$0	$0
86	May	2017	$0	$0	$0	$0	$0	$0	$0	$0
87	June	2017	$0	$0	$0	$0	$0	$0	$0	$0
88	July	2017	$0	$0	$0	$0	$0	$0	$0	$0
89	August	2017	$0	$0	$0	$0	$0	$0	$0	$0
90	September	2017	$0	$0	$0	$0	$0	$0	$0	$0
91	October	2017	$0	$0	$0	$0	$0	$0	$0	$0
92	November	2017	$0	$0	$0	$0	$0	$0	$0	$0
93	December	2017	$0	$0	$0	$0	$0	$0	$0	$0
94	January	2018	$0	$0	$0	$0	$0	$0	$0	$0
95	February	2018	$0	$0	$0	$0	$0	$0	$0	$0
96	March	2018	$0	$0	$0	$0	$0	$0	$0	$0
97	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
98	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
99	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
100	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
101	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
102	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
103	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
104	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
105	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
106	**13-Month Averages:**									**$0**

3c) Project: South of Kramer

Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
107	December	2016	---	---	---	---	---	---	$4,204,927	---
108	January	2017	$23,974	$1,798	$25,772	$0	$0	$0	$4,230,699	$25,772
109	February	2017	$42,882	$3,216	$46,098	$0	$0	$0	$4,276,797	$71,870
110	March	2017	$91,249	$6,844	$98,093	$0	$0	$0	$4,374,890	$169,963
111	April	2017	$50,000	$3,750	$53,750	$0	$0	$0	$4,428,640	$223,713
112	May	2017	$50,000	$3,750	$53,750	$0	$0	$0	$4,482,390	$277,463
113	June	2017	$50,000	$3,750	$53,750	$0	$0	$0	$4,536,140	$331,213
114	July	2017	$43,144	$3,236	$46,380	$0	$0	$0	$4,582,520	$377,593
115	August	2017	$50,000	$3,750	$53,750	$0	$0	$0	$4,636,270	$431,343
116	September	2017	$50,000	$3,750	$53,750	$0	$0	$0	$4,690,020	$485,093
117	October	2017	$40,000	$3,000	$43,000	$0	$0	$0	$4,733,020	$528,093
118	November	2017	$35,000	$2,625	$37,625	$0	$0	$0	$4,770,645	$565,718
119	December	2017	$24,000	$1,800	$25,800	$0	$0	$0	$4,796,445	$591,518
120	January	2018	$75,000	$5,625	$80,625	$0	$0	$0	$4,877,070	$672,143
121	February	2018	$75,000	$5,625	$80,625	$0	$0	$0	$4,957,695	$752,768
122	March	2018	$125,000	$9,375	$134,375	$0	$0	$0	$5,092,070	$887,143
123	April	2018	$125,000	$9,375	$134,375	$0	$0	$0	$5,226,445	$1,021,518
124	May	2018	$200,000	$15,000	$215,000	$0	$0	$0	$5,441,445	$1,236,518
125	June	2018	$250,000	$18,750	$268,750	$0	$0	$0	$5,710,195	$1,505,268
126	July	2018	$375,000	$28,125	$403,125	$0	$0	$0	$6,113,320	$1,908,393
127	August	2018	$375,000	$28,125	$403,125	$0	$0	$0	$6,516,445	$2,311,518
128	September	2018	$375,000	$28,125	$403,125	$0	$0	$0	$6,919,570	$2,714,643
129	October	2018	$375,000	$28,125	$403,125	$0	$0	$0	$7,322,695	$3,117,768
130	November	2018	$300,000	$22,500	$322,500	$0	$0	$0	$7,645,195	$3,440,268
131	December	2018	$250,000	$18,750	$268,750	$0	$0	$0	$7,913,945	$3,709,018
132	**13-Month Averages:**									**$1,836,037**

3d) Project: West of Devers

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
133	December	2016	---	---	---	---	---	---	$69,685,245	---
134	January	2017	$427,983	$32,099	$460,082	$0	$0	$0	$70,145,326	$460,082
135	February	2017	$747,590	$56,069	$803,659	$0	$0	$0	$70,948,986	$1,263,741
136	March	2017	$2,489,501	$186,713	$2,676,213	$0	$0	$0	$73,625,199	$3,939,954
137	April	2017	$993,609	$74,521	$1,068,130	$0	$0	$0	$74,693,329	$5,008,084
138	May	2017	$1,393,303	$104,498	$1,497,801	$0	$0	$0	$76,191,129	$6,505,885
139	June	2017	$1,354,552	$101,591	$1,456,143	$0	$0	$0	$77,647,273	$7,962,028
140	July	2017	$3,567,311	$267,548	$3,834,859	$0	$0	$0	$81,482,132	$11,796,887
141	August	2017	$4,249,979	$318,748	$4,568,727	$0	$0	$0	$86,050,859	$16,365,615
142	September	2017	$5,137,763	$385,332	$5,523,095	$0	$0	$0	$91,573,955	$21,888,710
143	October	2017	$5,018,559	$376,392	$5,394,951	$0	$0	$0	$96,968,906	$27,283,661
144	November	2017	$4,063,589	$304,769	$4,368,358	$0	$0	$0	$101,337,264	$31,652,019
145	December	2017	$8,316,849	$623,764	$8,940,613	$0	$0	$0	$110,277,876	$40,592,632
146	January	2018	$8,471,000	$635,325	$9,106,325	$0	$0	$0	$119,384,201	$49,698,957
147	February	2018	$8,671,000	$650,325	$9,321,325	$0	$0	$0	$128,705,526	$59,020,282
148	March	2018	$20,991,000	$1,574,325	$22,565,325	$0	$0	$0	$151,270,851	$81,585,607
149	April	2018	$20,991,000	$1,574,325	$22,565,325	$0	$0	$0	$173,836,176	$104,150,932
150	May	2018	$21,071,000	$1,580,325	$22,651,325	$0	$0	$0	$196,487,501	$126,802,257
151	June	2018	$21,060,000	$1,579,500	$22,639,500	$0	$0	$0	$219,127,001	$149,441,757
152	July	2018	$21,140,000	$1,585,500	$22,725,500	$0	$0	$0	$241,852,501	$172,167,257
153	August	2018	$21,193,000	$1,589,475	$22,782,475	$0	$0	$0	$264,634,976	$194,949,732
154	September	2018	$23,061,000	$1,729,575	$24,790,575	$0	$0	$0	$289,425,551	$219,740,307
155	October	2018	$28,552,000	$2,141,400	$30,693,400	$0	$0	$0	$320,118,951	$250,433,707
156	November	2018	$22,224,000	$1,666,800	$23,890,800	$0	$0	$0	$344,009,751	$274,324,507
157	December	2018	$22,389,000	$1,679,175	$24,068,175	$0	$0	$0	$368,077,926	$298,392,682
158	**13-Month Averages:**									**$155,484,662**

3e) Project: Red Bluff

Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
159	December	2016	---	---	---	---	---	---	$0	---
160	January	2017	$0	$0	$0	$0	$0	$0	$0	$0
161	February	2017	$3,269	$245	$3,515	$3,269	$0	$245	$0	$0
162	March	2017	$2,029	$152	$2,181	$2,029	$0	$152	$0	$0
163	April	2017	$0	$0	$0	$0	$0	$0	$0	$0
164	May	2017	$0	$0	$0	$0	$0	$0	$0	$0
165	June	2017	$0	$0	$0	$0	$0	$0	$0	$0
166	July	2017	$0	$0	$0	$0	$0	$0	$0	$0
167	August	2017	$0	$0	$0	$0	$0	$0	$0	$0
168	September	2017	$0	$0	$0	$0	$0	$0	$0	$0
169	October	2017	$0	$0	$0	$0	$0	$0	$0	$0
170	November	2017	$0	$0	$0	$0	$0	$0	$0	$0
171	December	2017	$0	$0	$0	$0	$0	$0	$0	$0
172	January	2018	$0	$0	$0	$0	$0	$0	$0	$0
173	February	2018	$0	$0	$0	$0	$0	$0	$0	$0
174	March	2018	$0	$0	$0	$0	$0	$0	$0	$0
175	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
176	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
177	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
178	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
179	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
180	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
181	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
182	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
183	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
184	**13-Month Averages:**									**$0**

3f) Project: Whirlwind Substation Expansion

Line	Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unload Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
185	December	2016	---	---	---	---	---	---	$26,943,987	---
186	January	2017	$654,164	$49,062	$703,226	$0	$0	$0	$27,647,213	$703,226
187	February	2017	$879,331	$65,950	$945,281	$0	$0	$0	$28,592,494	$1,648,507
188	March	2017	$3,461,579	$259,618	$3,721,198	$0	$0	$0	$32,313,692	$5,369,705
189	April	2017	$661,932	$49,645	$711,577	$31,960,130	$26,336,913	$421,741	$643,398	-$26,300,590
190	May	2017	$161,932	$12,145	$174,077	$150,000	$0	$11,250	$656,225	-$26,287,762
191	June	2017	$161,932	$12,145	$174,077	$814,728	$607,075	$15,574	$0	-$26,943,987
192	July	2017	$86,932	$6,520	$93,452	$86,932	$0	$6,520	$0	-$26,943,987
193	August	2017	$13,932	$1,045	$14,977	$13,932	$0	$1,045	$0	-$26,943,987
194	September	2017	$11,932	$895	$12,827	$11,932	$0	$895	$0	-$26,943,987
195	October	2017	$11,932	$895	$12,827	$11,932	$0	$895	$0	-$26,943,987
196	November	2017	$11,932	$895	$12,827	$11,932	$0	$895	$0	-$26,943,987
197	December	2017	$11,932	$895	$12,827	$11,932	$0	$895	$0	-$26,943,987
198	January	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
199	February	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
200	March	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
201	April	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
202	May	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
203	June	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
204	July	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
205	August	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
206	September	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
207	October	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
208	November	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
209	December	2018	$0	$0	$0	$0	$0	$0	$0	-$26,943,987
210	**13-Month Averages:**									**-$26,943,987**

3g) Project: Colorado River Substation Expansion

Line	Month	Year	Forecast Expenditures	Corporate Overheads	Total CWIP Exp	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
211	December	2016	---	---	---	---	---	---	$0	---
212	January	2017	-$335,081	-$25,131	-$360,213	-$335,081	$0	-$25,131	$0	$0
213	February	2017	$111,070	$8,330	$119,400	$111,070	$0	$8,330	$0	$0
214	March	2017	$98,479	$7,386	$105,865	$98,479	$0	$7,386	$0	$0
215	April	2017	$15,000	$1,125	$16,125	$15,000	$0	$1,125	$0	$0
216	May	2017	$50,000	$3,750	$53,750	$50,000	$0	$3,750	$0	$0
217	June	2017	$50,000	$3,750	$53,750	$50,000	$0	$3,750	$0	$0
218	July	2017	$33,000	$2,475	$35,475	$33,000	$0	$2,475	$0	$0
219	August	2017	$0	$0	$0	$0	$0	$0	$0	$0
220	September	2017	$0	$0	$0	$0	$0	$0	$0	$0
221	October	2017	$0	$0	$0	$0	$0	$0	$0	$0
222	November	2017	$0	$0	$0	$0	$0	$0	$0	$0
223	December	2017	$0	$0	$0	$0	$0	$0	$0	$0
224	January	2018	$0	$0	$0	$0	$0	$0	$0	$0
225	February	2018	$0	$0	$0	$0	$0	$0	$0	$0
226	March	2018	$0	$0	$0	$0	$0	$0	$0	$0
227	April	2018	$0	$0	$0	$0	$0	$0	$0	$0
228	May	2018	$0	$0	$0	$0	$0	$0	$0	$0
229	June	2018	$0	$0	$0	$0	$0	$0	$0	$0
230	July	2018	$0	$0	$0	$0	$0	$0	$0	$0
231	August	2018	$0	$0	$0	$0	$0	$0	$0	$0
232	September	2018	$0	$0	$0	$0	$0	$0	$0	$0
233	October	2018	$0	$0	$0	$0	$0	$0	$0	$0
234	November	2018	$0	$0	$0	$0	$0	$0	$0	$0
235	December	2018	$0	$0	$0	$0	$0	$0	$0	$0
236	**13-Month Averages:**									**$0**

3h) Project:

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
237	December	2016	---	---	---	---	---	---	$0	---
238	January	2017	$0	$0	$0			$0	$0	$0
239	February	2017	$0	$0	$0			$0	$0	$0
240	March	2017	$0	$0	$0			$0	$0	$0
241	April	2017		$0	$0			$0	$0	$0
242	May	2017		$0	$0			$0	$0	$0
243	June	2017		$0	$0			$0	$0	$0
244	July	2017		$0	$0			$0	$0	$0
245	August	2017		$0	$0			$0	$0	$0
246	September	2017		$0	$0			$0	$0	$0
247	October	2017		$0	$0			$0	$0	$0
248	November	2017		$0	$0			$0	$0	$0
249	December	2017		$0	$0			$0	$0	$0
250	January	2018		$0	$0			$0	$0	$0
251	February	2018		$0	$0			$0	$0	$0
252	March	2018		$0	$0			$0	$0	$0
253	April	2018		$0	$0			$0	$0	$0
254	May	2018		$0	$0			$0	$0	$0
255	June	2018		$0	$0			$0	$0	$0
256	July	2018		$0	$0			$0	$0	$0
257	August	2018		$0	$0			$0	$0	$0
258	September	2018		$0	$0			$0	$0	$0
259	October	2018		$0	$0			$0	$0	$0
260	November	2018		$0	$0			$0	$0	$0
261	December	2018		$0	$0			$0	$0	$0
262	**13-Month Averages:**									**$0**

3i) Project:

Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
263	December	2016	---	---	---	---	---	---	$0	---
264	January	2017		$0	$0			$0	$0	$0
265	February	2017		$0	$0			$0	$0	$0
266	March	2017		$0	$0			$0	$0	$0
267	April	2017		$0	$0			$0	$0	$0
268	May	2017		$0	$0			$0	$0	$0
269	June	2017		$0	$0			$0	$0	$0
270	July	2017		$0	$0			$0	$0	$0
271	August	2017		$0	$0			$0	$0	$0
272	September	2017		$0	$0			$0	$0	$0
273	October	2017		$0	$0			$0	$0	$0
274	November	2017		$0	$0			$0	$0	$0
275	December	2017		$0	$0			$0	$0	$0
276	January	2018		$0	$0			$0	$0	$0
277	February	2018		$0	$0			$0	$0	$0
278	March	2018		$0	$0			$0	$0	$0
279	April	2018		$0	$0			$0	$0	$0
280	May	2018		$0	$0			$0	$0	$0
281	June	2018		$0	$0			$0	$0	$0
282	July	2018		$0	$0			$0	$0	$0
283	August	2018		$0	$0			$0	$0	$0
284	September	2018		$0	$0			$0	$0	$0
285	October	2018		$0	$0			$0	$0	$0
286	November	2018		$0	$0			$0	$0	$0
287	December	2018		$0	$0			$0	$0	$0
288	**13-Month Averages:**									**$0**

3j) Project: add additional projects below this line (See Instruction 3)

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
				= C1 * 16-Plnt Add Line 74	= C1 + C2			= (C4 - C5) * 16-Plnt Add Line 74	= Prior Month C7 + C3 - C4 - C6	= C7 - Dec Prior Year C7
Line	**Month**	**Year**	**Forecast Expenditures**	**Corporate Overheads**	**Total CWIP Exp**	**Unloaded Total Plant Adds**	**Prior Period CWIP Closed**	**Over Heads Closed to PIS**	**Forecast Period CWIP**	**Forecast Period Incremental CWIP**
289	December	2016	---	---	---	---	---	---	$0	---
290	January	2017		$0	$0			$0	$0	$0
291	February	2017		$0	$0			$0	$0	$0
292	March	2017		$0	$0			$0	$0	$0
293	April	2017		$0	$0			$0	$0	$0
294	May	2017		$0	$0			$0	$0	$0
295	June	2017		$0	$0			$0	$0	$0
296	July	2017		$0	$0			$0	$0	$0
297	August	2017		$0	$0			$0	$0	$0
298	September	2017		$0	$0			$0	$0	$0
299	October	2017		$0	$0			$0	$0	$0
300	November	2017		$0	$0			$0	$0	$0
301	December	2017		$0	$0			$0	$0	$0
302	January	2018		$0	$0			$0	$0	$0
303	February	2018		$0	$0			$0	$0	$0
304	March	2018		$0	$0			$0	$0	$0
305	April	2018		$0	$0			$0	$0	$0
306	May	2018		$0	$0			$0	$0	$0
307	June	2018		$0	$0			$0	$0	$0
308	July	2018		$0	$0			$0	$0	$0
309	August	2018		$0	$0			$0	$0	$0
310	September	2018		$0	$0			$0	$0	$0
311	October	2018		$0	$0			$0	$0	$0
312	November	2018		$0	$0			$0	$0	$0
313	December	2018		$0	$0			$0	$0	$0
314	**13-Month Averages:**									**$0**

Notes:
1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).
2) Sum of project specific values from lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,…

Instructions:
1) Enter recorded amounts of CWIP during Prior Year on Lines 1-13, 15-27 (including December of year previous to Prior Year).
2) Enter forecast project specific values on lines 55-79, 81-105, 107-131, 133-157, 159-183, 185-209, 211-235, 237-261, 263-287, 289-313,...
3) If Commission approval is granted to include CWIP in Rate Base for additional projects, include additional tables for each of those additional projects.

TRANSMISSION PLANT HELD FOR FUTURE USE

Inputs are shaded yellow

Transmission Plant Held for Future Use shall be amounts of Electric Plant Held for Future Use (account 105) intended to be placed under the Operational Control of the ISO, plus an allocated amount of any General Electric Plant Held for Future Use, with the allocation factor being the Transmission Wages and Salaries AF.

Line		Beginning of Year Balance	End of Year Balance	Source
1	Total Electric PHFU	$16,261,747	$16,261,841	FF1 page 214.47d

Plant intended to be placed under the Operational Control of the ISO:

	Col 1 Description	Col 2 Type of Plant	Col 3 Beginning of Year Balance	Col 4 End of Year Balance	Col 5 Source
2a	Alberhill	Sub	$9,942,155	$9,942,155	SCE records
2b					
2c					
2d					
2e					
2f					
2g					
2h					
	…				
3		Total:	$9,942,155	$9,942,155	Sum of above lines

		Beginning of Year Balance	End of Year Balance	Source
4	General Plant Held for Future Use	$0	$0	FF1 page 214
5	Wages and Salaries AF:	6.165%	6.165%	27-Allocators, L 9
6	Portion for Transmission PHFU:	$0	$0	L 4 * L 5

All other Electric Plant Held for Future Use not intended to be placed under the Operational Control of the ISO:

		Beginning of Year Balance	End of Year Balance	Source
7		$6,319,593	$6,319,686	Note 1

	Transmission PHFU:	Beginning of Year Balance	End of Year Balance	Source
8		$9,942,155	$9,942,155	L 3 + L 6
9	Average of BOY and EOY Transmission PHFU:	$9,942,155		Sum of Line 8 / 2

Calculation of Gain or Loss on Transmission Plant Held for Future Use -- Land

			Source
10	Gain or Loss on Transmission Plant Held for Future Use --- Land	$0	SCE Records

Instructions:

1) For any Electric Plant Held for Future Use intended to be placed under the Operational Control of the ISO, list on lines 2a, 2b, etc. Provide description in Column 1. Note type of plant (land or other) in Column 2. Under "Source" (Column 5), state the line number on FERC Form 1 page 214 from which the amount is derived. BOY amount will be EOY value from previous year FERC Form 1, EOY amount will be in current year FF1.
2) For any Electric Plant Held for Future Use classified as General note amount on Line 4.
3) Add additional lines 2 i, j, k, etc. as necessary to include additional projects intended to be placed under the Operational Control of the ISO.
4) Gains and Losses on Transmission Plant Held for Future Use - Land is treated in accordance with Commission policy. Any gain or loss on non-land portions of Transmission Plant Held for Future Use is not included.

Notes:

1) Amount of Line 1 not intended to be placed under the Operational Control of the ISO.

Determination of amount of Abandoned Plant and Abandoned Plant Amortization Expense

Input data is shaded yellow

Initially Abandoned Plant Amortization Expense and Abandoned Plant are both zero.

Upon Commission approval of recovery of abandoned plant costs for a specific project or projects, SCE will complete this worksheet in accordance with that Order.

	Project	Commission Order
Orders Providing for Abandoned Plant Cost Recovery:	CWLTP (Coolwater-Lugo Transmission Project)	159 FERC ¶ 62,038 dated April 10, 2017
	…	…

Abandoned Plant for each project represents the amount of costs that the Order approves for inclusion in Rate Base.

Abandoned Plant Amortization Expense for each project represents the annual amortization of abandoned costs that the Order approves as an annual expense.

Line		Amount for Prior Year	Note:
1	Abandoned Plant Amortization Expense:	$37,069,049	Sum of projects below for PY.
2	Abandoned Plant (BOY):	$37,069,049	Sum of projects below for PY.
3	Abandoned Plant (EOY):	$0	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	$18,534,525	Average of Lines 2 and 3.
5	HV Abandoned Plant (BOY):	$37,069,049	Sum of projects below for PY.

6 **First Project:** CWLTP **2nd Project:** Fill in Name

	Year	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense	EOY Abandoned Plant	EOY HV Abandoned Plant (Note 1)	Abandoned Plant Amort. Expense
7	2015	37,069,049	37,069,049	0			
8	2016	0	0	37,069,049			
9	2017						
10	2018						
11	2019						
12	2020						
13	2021						
14	2022						
15	2023						
16	2024						
17	2025						
18	…						

Notes:
1) "EOY HV Abandoned Plant" is amount of "EOY Abandoned Plant" that would have been High Voltage (>= 200 kV).

Instructions:
1) Upon Commission approval of recovery of abandoned plant costs for a project:
   a) Fill in the name the project in order (First Project, Second Project, etc.).
   b) Fill in the table with annual End of Year ("EOY") Abandoned Plant, EOY HV Abandoned Plant, and Abandoned Plant Amortization Expense amounts in Accordance with the Order.
   If table can not be filled out completely, fill out at least through the Prior Year at issue.
   c) Sum project-specific amounts for each project and enter in lines 1, 2, and 3 for the Prior Year at issue.
   (BOY value is EOY value from previous year)
2) Add additional projects if necessary in same format.
3) Add additional years past 2025 if necessary.

Calculation of Components of Working Capital

Inputs are shaded yellow

1) Calculation of Materials and Supplies

Materials and Supplies is the amount of total Account 154 Materials and Supplies times the Transmission Wages and Salaries AF

Line	Month	Year	Data Source	Total Materials and Supplies Balances	Notes
1	December	2015	FF1 227.12b	$251,648,702	Beginning of year ("BOY") amount
2	January	2016	SCE Records	$263,918,894	
3	February	2016	SCE Records	$253,005,820	
4	March	2016	SCE Records	$249,977,460	
5	April	2016	SCE Records	$249,664,714	
6	May	2016	SCE Records	$247,107,782	
7	June	2016	SCE Records	$248,949,526	
8	July	2016	SCE Records	$248,835,535	
9	August	2016	SCE Records	$250,822,798	
10	September	2016	SCE Records	$252,012,870	
11	October	2016	SCE Records	$251,388,826	
12	November	2016	SCE Records	$251,492,561	
13	December	2016	FF1 227.12c	$237,798,844	End of Year ("EOY") amount
14			13-Month Average Value Account 154:	$250,509,564	(Sum Line 1 to Line 13) / 13
15			Transmission Wages and Salaries AF:	6.165%	27-Allocators, Line 9
16	**Materials and Supplies**		EOY Value:	$14,660,302	Line 13 * Line 15
17			13-Month Average Value:	$15,443,918	Line 14 * Line 15

2) Calculation of Prepayments

Prepayments is an allocated portion of Total Prepayments based on the Transmission Wages and Salaries Allocation Factor.

Line	Month	Year	Data Source	Total Prepayments Balances	Notes
18	December	2015	Note 1, c	$91,007,488	See Note 1, c
19	January	2016	SCE Records	$94,125,416	
20	February	2016	SCE Records	$82,464,132	
21	March	2016	SCE Records	$73,891,432	
22	April	2016	SCE Records	$109,166,805	
23	May	2016	SCE Records	$79,044,870	
24	June	2016	SCE Records	$52,816,887	
25	July	2016	SCE Records	$92,736,373	
26	August	2016	SCE Records	$87,831,660	
27	September	2016	SCE Records	$68,578,067	
28	October	2016	SCE Records	$66,851,094	
29	November	2016	SCE Records	$77,479,882	
30	December	2016	Note 1, f	$99,369,093	See Note 1, f
	a) 13-Month Average Calculation				
31			13-Month AverageValue:	$82,720,246.08	(Sum Line 18 to Line 30) / 13
32			Transmission Wages and Salaries AF:	6.1650%	27-Allocators, Line 9
33			Prepayments:	$5,099,704	Line 31 * Line 32
	b) EOY calculation				
34			EOY Value:	$99,369,093	Line 30
35			Transmission Wages and Salaries AF:	6.1650%	27-Allocators, Line 9
36			Prepayments:	$6,126,106	Line 34 * Line 35

Notes:

1) Remove any amounts related to years prior to 2012 on b and e below.

	Beginning of Year Amount	Prepayments Balances	Source
a	FERC Form 1 Acct. 165 Recorded Amount:	$91,007,488	FF1 111.57d
b	Prior Period Adjustment:	$0	Note 1
c	BOY Prepayments Amount:	$ 91,007,488	a - b

	End of Year Amount	Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	$114,171,737	FF1 111.57c
e	Prior Period Adjustment:	$14,802,644	Note 1
f	EOY Prepayments Amount:	$ 99,369,093	d - e

Plant Balances For Incentive Projects Receiving either ROE Incentives ("Transmission Incentive Plant") or CWIP ("CWIP Plant")

Input data is shaded yellow

A) Summary of Incentive Project plant balances receiving ROE incentives ("Transmission Incentive Plant") and/or CWIP ("CWIP Plant") and calculation of balances needed to determine the following:

1) Rate Base in Prior Year
2) Prior Year Incentive Rate Base - End of Year
3) Prior Year Incentive Rate Base - 13-Month Average

Transmission Incentive Project plant balances and CWIP Plant may affect the following:
a) CWIP Plant during the Prior Year is included in Rate Base (used in Prior Year TRR and True Up TRR).
b) Forecast Period Incremental CWIP contributes to Incremental Forecast Period TRR
c) CWIP Plant receiving an ROE adder contributes to Prior Year Incentive Rate Base - EOY, or Prior Year Incentive Rate Base - 13 Month Average as appropriate.
d) "TIP Net Plant In Service" at EOY Prior Year is used to calculate the PY Incentive Rate Base (on EOY basis).
e) "TIP Net Plant In Service" in PY is used to calculate the Prior Year Incentive Rate Base (on 13-month average basis).

1) Summary of CWIP Plant in Prior Year and Forecast Period

Line	Incentive Project	Col 1 Prior Year End-of-Year CWIP Plant Amount	Col 2 Prior Year 13-Month Average CWIP Plant Amount	Col 3 Forecast Period Incremental CWIP 13-Month Avg. Amount	Notes:
1	1) Tehachapi	$14,915,548	$194,883,792	-$14,915,548	10-CWIP Lines 13, 14, and 80
2	2) Devers-Colorado River	$0	$0	$0	10-CWIP Lines 13, 14, and 106
3	3) South of Kramer	$4,204,927	$3,394,860	$1,836,037	10-CWIP Lines 13, 14, and 132
4	4) West of Devers	$69,685,245	$56,339,988	$155,484,662	10-CWIP Lines 13, 14, and 158
5	5) Red Bluff	$0	$709,238	$0	10-CWIP Lines 13, 14, and 184
6	6) Whirlwind Substation Exp.	$26,943,987	$16,606,020	-$26,943,987	10-CWIP Lines 27, 28, and 210
7	7) Colorado River Sub. Exp.	$0	$0	$0	10-CWIP Lines 27, 28, and 236
8	8)	$0	$0	$0	10-CWIP Lines 27, 28, and 262
9	9)	$0	$0	$0	10-CWIP Lines 27, 28, and 288
10	…	---	---	---	…
11					
12	Totals:	$115,749,706	$271,933,898	$115,461,165	

2) Summary of Prior Year Incentive Rate Base amounts (EOY Values)

Line		Col 1 = C2 + C3 Prior Year Incentive Rate Base	Col 2 EOY CWIP Portion	Col 3 EOY TIP Net Plant In Service	Notes:
13	1) Rancho Vista	$154,978,996	$0	$154,978,996	Line 37, C4
14	2) Tehachapi	$2,776,011,901	$14,915,548	$2,761,096,354	Line 1, C1, and Line 37, C2
15	3) Devers-Colorado River	$707,569,233	$0	$707,569,233	Line 2, C1, and Line 37, C3
16	…	---	---	---	…
17					
18	Total PY Incentive Net Plant:	$3,638,560,131			End of Year

3) Summary of Prior Year Incentive Rate Base amounts (13-Month Average values)

Line	Incentive Project	Col 1 = C2 + C3 Prior Year Incentive Rate Base	Col 2 13-Month Avg. CWIP Portion	Col 3 13-Month Avg. TIP Net Plant In Service Portion	Notes:
19	1) Rancho Vista	$157,348,618	$0	$157,348,618	Line 38, C4
20	2) Tehachapi	$2,759,257,909	$194,883,792	$2,564,374,117	Line 1, C2, and Line 38, C2
21	3) Devers-Colorado R	$717,950,118	$0	$717,950,118	Line 2, C2, and Line 38, C3
22	…	---	---	---	…
23					
24	Total PY Incentive Net Plant:	$3,634,556,645			13 Month Average

4) Prior Year TIP Net Plant In Service

	Prior Year Month	Year	Col 1 Total TIP Net Plant In Service	Col 2 L 53 to L 65, C3 Tehachapi	Col 3 L 79 to L 91, C3 Devers to Colorado River	Col 4 L 66 to L 78, C3 Rancho Vista	Col 5	Notes
25	December	2015	$3,384,224,921	$2,495,479,773	$729,026,909	$159,718,239	---	←December of
26	January	2016	$3,378,443,942	$2,491,755,773	$727,364,867	$159,323,302	---	year previous
27	February	2016	$3,373,276,330	$2,489,776,745	$724,571,220	$158,928,365	---	to Prior Year
28	March	2016	$3,376,692,256	$2,495,232,420	$722,926,408	$158,533,428	---	
29	April	2016	$3,374,083,891	$2,494,893,777	$721,051,623	$158,138,491	---	
30	May	2016	$3,367,918,909	$2,490,772,744	$719,402,611	$157,743,554	---	
31	June	2016	$3,363,020,794	$2,487,916,881	$717,755,295	$157,348,618	---	
32	July	2016	$3,356,341,299	$2,483,282,938	$716,104,680	$156,953,681	---	
33	August	2016	$3,347,662,478	$2,476,650,075	$714,453,659	$156,558,744	---	
34	September	2016	$3,583,983,495	$2,715,017,702	$712,801,986	$156,163,807	---	
35	October	2016	$3,594,218,907	$2,727,347,332	$711,102,705	$155,768,870	---	
36	November	2016	$3,592,235,273	$2,727,641,003	$709,220,337	$155,373,933	---	
37	December	2016	$3,623,644,583	$2,761,096,354	$707,569,233	$154,978,996	---	
38	13 Month Averages:		$3,439,672,852	$2,564,374,117	$717,950,118	$157,348,618		

5) Total Transmission Activity for Incentive Projects

	Prior Year Month	Year	Col 1 Total Transmission Activity for Incentive Projects	Col 2 Account 360-362 Activity	Col 3 = C1 - C2 Account 350-359 Activity for Incentive Projects	Source
39	December	2015	$0	$0	$0	C1: Sum of below projects
40	January	2016	$2,046,368	$0	$2,046,368	for each month
41	February	2016	$11,562,821	$0	$11,562,821	
42	March	2016	$11,199,828	$0	$11,199,828	
43	April	2016	$5,071,299	$0	$5,071,299	
44	May	2016	$1,593,454	$0	$1,593,454	
45	June	2016	$2,856,175	$0	$2,856,175	
46	July	2016	$1,114,638	$0	$1,114,638	
47	August	2016	-$841,844	$0	-$841,844	
48	September	2016	$244,140,350	$0	$244,140,350	
49	October	2016	$18,523,001	$0	$18,523,001	
50	November	2016	$6,351,778	$0	$6,351,778	
51	December	2016	$39,688,626	$0	$39,688,626	
52	Total		$343,306,492	$0	$343,306,492	

6) Calculation of Prior Year Net Plant in Service amounts for each Incentive Project

a) Tehachapi

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
53	December	2015	$2,663,183,372	$167,703,599	$2,495,479,773	$0
54	January	2016	$2,665,129,021	$173,373,248	$2,491,755,773	$1,945,649
55	February	2016	$2,668,823,728	$179,046,983	$2,489,776,745	$3,694,707
56	March	2016	$2,679,961,025	$184,728,605	$2,495,232,420	$11,137,297
57	April	2016	$2,685,306,647	$190,412,870	$2,494,893,777	$5,345,622
58	May	2016	$2,686,883,031	$196,110,287	$2,490,772,744	$1,576,384
59	June	2016	$2,689,728,286	$201,811,404	$2,487,916,881	$2,845,255
60	July	2016	$2,690,801,506	$207,518,568	$2,483,282,938	$1,073,221
61	August	2016	$2,689,878,089	$213,228,014	$2,476,650,075	-$923,417
62	September	2016	$2,933,960,339	$218,942,637	$2,715,017,702	$244,082,249
63	October	2016	$2,952,458,626	$225,111,294	$2,727,347,332	$18,498,287
64	November	2016	$2,958,963,118	$231,322,115	$2,727,641,003	$6,504,492
65	December	2016	$2,998,641,930	$237,545,576	$2,761,096,354	$39,678,812

	b) Rancho Vista		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
66	December	2015	$191,508,708	$31,790,469	$159,718,239	$0
67	January	2016	$191,508,708	$32,185,406	$159,323,302	$0
68	February	2016	$191,508,708	$32,580,343	$158,928,365	$0
69	March	2016	$191,508,708	$32,975,280	$158,533,428	$0
70	April	2016	$191,508,708	$33,370,217	$158,138,491	$0
71	May	2016	$191,508,708	$33,765,154	$157,743,554	$0
72	June	2016	$191,508,708	$34,160,090	$157,348,618	$0
73	July	2016	$191,508,708	$34,555,027	$156,953,681	$0
74	August	2016	$191,508,708	$34,949,964	$156,558,744	$0
75	September	2016	$191,508,708	$35,344,901	$156,163,807	$0
76	October	2016	$191,508,708	$35,739,838	$155,768,870	$0
77	November	2016	$191,508,708	$36,134,775	$155,373,933	$0
78	December	2016	$191,508,708	$36,529,712	$154,978,996	$0

	c) Devers to Colorado River		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
79	December	2015	$775,314,541	$46,287,632	$729,026,909	$0
80	January	2016	$775,308,404	$47,943,537	$727,364,867	-$6,138
81	February	2016	$774,170,650	$49,599,429	$724,571,220	-$1,137,754
82	March	2016	$774,178,096	$51,251,688	$722,926,408	$7,447
83	April	2016	$773,955,586	$52,903,963	$721,051,623	-$222,510
84	May	2016	$773,958,249	$54,555,638	$719,402,611	$2,663
85	June	2016	$773,962,614	$56,207,319	$717,755,295	$4,366
86	July	2016	$773,963,689	$57,859,010	$716,104,680	$1,075
87	August	2016	$773,964,361	$59,510,702	$714,453,659	$672
88	September	2016	$773,964,383	$61,162,397	$712,801,986	$22
89	October	2016	$773,916,797	$62,814,092	$711,102,705	-$47,586
90	November	2016	$773,686,025	$64,465,688	$709,220,337	-$230,772
91	December	2016	$773,686,037	$66,116,803	$707,569,233	$12

	d) South of Kramer		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
92	December	2015	$0	$0	$0	$0
93	January	2016	$0	$0	$0	$0
94	February	2016	$0	$0	$0	$0
95	March	2016	$0	$0	$0	$0
96	April	2016	$0	$0	$0	$0
97	May	2016	$0	$0	$0	$0
98	June	2016	$0	$0	$0	$0
99	July	2016	$0	$0	$0	$0
100	August	2016	$0	$0	$0	$0
101	September	2016	$0	$0	$0	$0
102	October	2016	$0	$0	$0	$0
103	November	2016	$0	$0	$0	$0
104	December	2016	$0	$0	$0	$0

	e) West of Devers		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
105	December	2015	$0	$0	$0	$0
106	January	2016	$0	$0	$0	$0
107	February	2016	$0	$0	$0	$0
108	March	2016	$0	$0	$0	$0
109	April	2016	$0	$0	$0	$0
110	May	2016	$0	$0	$0	$0
111	June	2016	$0	$0	$0	$0
112	July	2016	$0	$0	$0	$0
113	August	2016	$0	$0	$0	$0
114	September	2016	$0	$0	$0	$0
115	October	2016	$0	$0	$0	$0
116	November	2016	$0	$0	$0	$0
117	December	2016	$0	$0	$0	$0

	f) Red Bluff		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
118	December	2015	$226,465,462	$13,667,285	$212,798,176	$0
119	January	2016	$226,566,589	$14,143,896	$212,422,693	$101,128
120	February	2016	$235,569,312	$14,621,185	$220,948,126	$9,002,722
121	March	2016	$235,569,038	$15,117,755	$220,451,283	-$273
122	April	2016	$235,574,239	$15,614,324	$219,959,916	$5,201
123	May	2016	$235,577,092	$16,110,904	$219,466,188	$2,853
124	June	2016	$235,578,588	$16,607,490	$218,971,098	$1,496
125	July	2016	$235,581,407	$17,104,080	$218,477,327	$2,819
126	August	2016	$235,581,826	$17,600,675	$217,981,151	$419
127	September	2016	$235,583,328	$18,097,271	$217,486,056	$1,501
128	October	2016	$235,589,252	$18,593,871	$216,995,381	$5,925
129	November	2016	$235,591,547	$19,090,483	$216,501,063	$2,294
130	December	2016	$235,590,583	$19,587,100	$216,003,483	-$964

	g) Whirlwind Substation Expansion		Col 1	Col 2	Col 3	Col 4
					= C1 - C2	= C1 - Previous Month C1
	Prior Year Month	Year	Plant In-Service	Accumulated Depreciation	Net Plant In Service	Transmission Activity
131	December	2015	$53,634,942	$1,700,860	$51,934,082	$0
132	January	2016	$53,636,121	$1,811,320	$51,824,801	$1,179
133	February	2016	$53,636,178	$1,921,783	$51,714,395	$57
134	March	2016	$53,636,834	$2,032,247	$51,604,588	$656
135	April	2016	$53,636,930	$2,142,711	$51,494,219	$96
136	May	2016	$53,637,716	$2,253,176	$51,384,540	$786
137	June	2016	$53,629,155	$2,363,642	$51,265,513	-$8,561
138	July	2016	$53,629,155	$2,474,091	$51,155,064	$0
139	August	2016	$53,629,155	$2,584,540	$51,044,615	$0
140	September	2016	$53,630,073	$2,695,009	$50,935,064	$918
141	October	2016	$53,628,337	$2,805,481	$50,822,856	-$1,736
142	November	2016	$53,627,431	$2,915,949	$50,711,482	-$906
143	December	2016	$53,627,431	$3,026,415	$50,601,016	$0

h) Colorado River Substation Expansion

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
144	December	2015	$70,732,251	$4,231,359	$66,500,892	$0
145	January	2016	$70,736,801	$4,377,930	$66,358,871	$4,550
146	February	2016	$70,739,890	$4,524,510	$66,215,380	$3,089
147	March	2016	$70,794,591	$4,671,097	$66,123,494	$54,701
148	April	2016	$70,737,481	$4,817,796	$65,919,686	-$57,110
149	May	2016	$70,748,250	$4,964,377	$65,783,873	$10,769
150	June	2016	$70,761,869	$5,110,981	$65,650,888	$13,619
151	July	2016	$70,799,392	$5,257,613	$65,541,779	$37,523
152	August	2016	$70,879,873	$5,404,322	$65,475,552	$80,481
153	September	2016	$70,935,533	$5,551,196	$65,384,337	$55,660
154	October	2016	$71,003,644	$5,698,186	$65,305,459	$68,111
155	November	2016	$71,080,313	$5,845,315	$65,234,998	$76,669
156	December	2016	$71,091,079	$5,992,602	$65,098,477	$10,766

i)

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
157	December				$0	$0
158	January				$0	$0
159	February				$0	$0
160	March				$0	$0
161	April				$0	$0
162	May				$0	$0
163	June				$0	$0
164	July				$0	$0
165	August				$0	$0
166	September				$0	$0
167	October				$0	$0
168	November				$0	$0
169	December				$0	$0

j)

	Prior Year Month	Year	Col 1 Plant In-Service	Col 2 Accumulated Depreciation	Col 3 = C1 - C2 Net Plant In Service	Col 4 = C1 - Previous Month C1 Transmission Activity
170	December				$0	$0
171	January				$0	$0
172	February				$0	$0
173	March				$0	$0
174	April				$0	$0
175	May				$0	$0
176	June				$0	$0
177	July				$0	$0
178	August				$0	$0
179	September				$0	$0
180	October				$0	$0
181	November				$0	$0
182	December				$0	$0

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:		**Cite:**
183	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
184	ROE adder:	0.75%	121 FERC ¶ 61,168 at P 129
185	100% Abandoned Plant:	No	-------
	B) Tehachapi Incentives Received:		**Cite:**
186	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
187	ROE adder:	1.25%	121 FERC ¶ 61,168 at P 129
188	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	C) Devers to Colorado River Incentives Received:		**Cite:**
189	CWIP:	Yes	121 FERC ¶ 61,168 at P 57
190	ROE adder:	1.00%	121 FERC ¶ 61,168 at 129; modified by ER10-160 Settlement, see
191			P2 and P3
192	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	D) Devers to Palo Verde 2 Incentives Received:		**Cite:**
193	CWIP:	No	121 FERC ¶ 61,168 at P 57; modified by ER10-160 Settlement, see
194			P2 and P3
195	ROE adder:	0.00%	121 FERC ¶ 61,168 at P 129; modified by ER10-160 Settlement, see
196			P 3 and P 7
197	100% Abandoned Plant:	Yes	121 FERC ¶ 61,168 at P 71
	E) South of Kramer Incentives Received:		**Cite:**
198	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
199	ROE adder:	0.00%	---
200	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	F) West of Devers Incentives Received:		**Cite:**
201	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
202	ROE adder:	0.00%	---
203	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	G) Red Bluff Incentives Received:		**Cite:**
204	CWIP:	Yes	133 FERC ¶ 61,107 at P 76
205	ROE adder:	0.00%	133 FERC ¶ 61,107 at P 102
206	100% Abandoned Plant:	Yes	133 FERC ¶ 61,107 at P 88
	H) Whirlwind Substation Expansion Incentives Received:		**Cite:**
207	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
208	ROE adder:	0.00%	---
209	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	I) Colorado River Substation Expansion Incentives Received:		**Cite:**
210	CWIP:	Yes	134 FERC ¶ 61,181 at P 79
211	ROE adder:	0.00%	---
212	100% Abandoned Plant:	Yes	134 FERC ¶ 61,181 at P 79
	J) Future Incentive Projects		**Cite:**
213	CWIP:	-	
214	ROE adder:	- %	
215	100% Abandoned Plant:	-	
	K) Future Incentive Projects		**Cite:**
216	CWIP:	-	
217	ROE adder:	- %	
218	100% Abandoned Plant:	-	
	L) Future Incentive Projects		**Cite:**
219	CWIP:		
220	ROE adder:		
221	100% Abandoned Plant:		
	…		

Instructions:

1) Upon Commission approval of any incentives for additional projects, add additional projects and provide cite to the Commission decision.

Determination of Incentive Adders Components of the TRR

Input data is shaded yellow

Two Incentive Adders are calculated:
a) The Prior Year Incentive Adder is a component of the Prior Year TRR.
b) The True Up Incentive Adder is a component of the True Up TRR.

1) Calculation of Incremental Return on Equity Factor

The Incremental Return on Equity Factor is the incremental Prior Year TRR expressed per 100 basis points of ROE incentive, for each million dollars of Incentive Net Plant. It is calculated according to the following formula:

IREF = CSCP * 0.01 * (1/(1 - CTR)) * $1,000,000

Line	where:		Value	Source
1	CSCP = Common Stock Capital Percentage		50.5931%	1-BaseTRR, L 47
2	CTR = Composite Tax Rate		40.7460%	1-BaseTRR, L 59
3		IREF =	$8,538	Above formula

2) Determination of multiplicative factors for use in calculating Incentive Adders:
Multiplicative factors are used to calculate the Incentive Adders on an Transmission Incentive Project specific basis.
Multiplicative factor for each project is the ratio of its ROE adder to 1%.

Line		ROE Adder	Multiplicative Factor	Source
4	1) Rancho Vista	0.75%	0.75	14-IncentivePlant, L 184
5	2) Tehachapi	1.25%	1.25	14-IncentivePlant, L 187
6	3) Devers to Col. River	1.00%	1.00	14-IncentivePlant, L 190
7				
8	…			

3) Calculation of Prior Year Incentive Adder (EOY)
1) Determine Prior Year Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of Prior Year Incentive Rate Base.
2) Sum project-specific Incentive Adders to yield the total Prior Year Incentive Adder.

Line		Prior Year Incentive Rate Base	Multiplicative Factor	Prior Year Incentive Adder	Source
9	1) Rancho Vista	$154,978,996	0.75	$992,448	14-IncentivePlant, L 13, Col. 1
10	2) Tehachapi	$2,776,011,901	1.25	$29,628,186	14-IncentivePlant, L 14, Col. 1
11	3) Devers to Col. River	$707,569,233	1.00	$6,041,471	14-IncentivePlant, L 15, Col. 1
12					
13	…				
14			Prior Year Incentive Adder =	$36,662,105	Sum of above PY Incentive Adders for each individual project

4) Calculation of True-Up Incentive Adder
1) Determine True Up Incentive Adder for each Incentive Project by multiplying the IREF, the Multiplicative Factor, and the million $ of True Up Incentive Net Plant.
2) Sum project-specific Incentive Adders to yield the total True Up Incentive Adder.

Line		True-Up Incentive Net Plant	Multiplicative Factor	True-Up Incentive Adder	Source
15	1) Rancho Vista	$157,348,618	0.75	$1,007,623	14-IncentivePlant, L 19, Col. 1
16	2) Tehachapi	$2,759,257,909	1.25	$29,449,372	14-IncentivePlant, L 20, Col. 1
17	3) Devers to Col. River	$717,950,118	1.00	$6,130,106	14-IncentivePlant, L 21, Col. 1
18					
19	…				
20			True-Up Incentive Adder =	$36,587,101	Sum of above PY Incentive Adders for each individual project

5) Calculation of Total ROE for Plant-In Service in the True Up TRR

a) Transmission Incentive Plant Net Plant In Service

Line	Incentive Project	13-Month Avg. TIP Net Plant In Service	Source
21	1) Rancho Vista	$157,348,618	14-IncentivePlant, L 19, Col. 3
22	2) Tehachapi	$2,564,374,117	14-IncentivePlant, L 20, Col. 3
23	3) Devers to Col. River	$717,950,118	14-IncentivePlant, L 21, Col. 3
24			
	…		

b) Calculation of ROE Adders on TIP Net Plant In Service

Line	Incentive Project	Col 1 True Up Incentive Adder	Col 2 After-Tax True Up Incentive Adder	Source
25	1) Rancho Vista	$1,007,623	$597,057	See Note 1
26	2) Tehachapi	$27,369,390	$16,217,459	See Note 1
27	3) Devers to Col. River	$6,130,106	$3,632,333	See Note 1
28				See Note 1
29	…			
30		Total:	$20,446,848	

c) Equity Portion of Plant In Service Rate Base

Line		Amount	Source
31	Total Rate Base:	$5,543,506,370	4-TUTRR, Line 18
32	CWIP Portion of Rate Base:	$271,933,898	4-TUTRR, Line 14
33	Plant In Service Rate Base:	$5,271,572,471	Line 31 - Line 32
34	Equity percentage:	50.5931%	1-BaseTRR, Line 47
35	Equity Portion of Plant In Service Rate Base:	$2,667,052,599	Line 33 * Line 34

d) Total ROE for Plant In Service in the True Up TRR

Line			
36	Plant In Service ROE Adder Percentage:	0.77%	Line 30 / Line 35
37	Base ROE (Including 50 basis point		
38	CAISO Participation Adder):	10.80%	1-BaseTRR, Line 50
39	Total ROE for Plant In Service in True Up TRR:	11.57%	Line 36 + Line 38

Instructions:
1) If additional projects receive ROE adders, add to end of lists, and include in calculation of each Incentive Adder.

Notes:
1) Column 1: The True Up Incentive Adder for each Incentive Project equals the IREF on Line 3, times the applicable Multiplicative Factor on Lines 15 to 18, times the million $ of TIP Net Plant In Service on Lines 21 to 24.
Column 2: The After Tax True Up Incentive Adder is derived by multiplying the amounts in Column 1 by (1 - CTR) (Where the CTR is on Line 2).

Forecast Plant Additions for In-Service ISO Transmission Plant

Yellow shaded cells are Input Data

Forecast Plant Additions represents the total increase in ISO Transmission Net Plant, not including CWIP,
during the Rate Year, incremental to the year-end Prior Year amount.
It is calculated on a 13-Month Average Basis during the Rate Year.

1) Total Plant Additions Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1 See Note 2 Unloaded Total Plant Adds	Col 2 See Note 2 Prior Period CWIP Closed	Col 3 See Note 2 Over Heads Closed to PIS	Col 4 See Note 2 Cost of Removal	Col 5 See Note 2 AFUDC Eligible Plant Additions	Col 6 See Note 2 AFUDC	Col 7 See Note 2 Incremental Gross Plant	Col 8 See Note 2 Depreciation Accrual	Col 9 See Note 2 Incremental Reserve	Col 10 See Note 2 Net Plant	Col 11 See Note 2 Unloaded Low Voltage Additions	Col 12 See Note 2 Loaded Low Voltage Additions
1	January	2017	$15,497,613	$1,042,927	$1,084,101	$1,230,413	$14,149,752	$424,493	$15,775,793	$0	-$1,230,413	$17,006,207	$42,318	$43,020
2	February	2017	$33,122,978	$16,379,141	$1,255,788	$1,323,866	$15,224,462	$456,734	$49,287,427	$35,942	-$2,518,338	$51,805,764	$84,636	$86,041
3	March	2017	$15,769,978	$134,081	$1,172,692	$1,230,413	$14,149,752	$424,493	$65,424,176	$112,291	-$3,636,460	$69,060,637	$126,954	$129,061
4	April	2017	$65,874,663	$43,619,049	$1,669,171	$1,380,342	$15,873,932	$476,218	$132,063,887	$149,055	-$4,867,747	$136,931,634	$169,272	$172,082
5	May	2017	$15,378,120	$134,081	$1,143,303	$1,230,413	$14,149,752	$424,493	$147,779,389	$300,879	-$5,797,281	$153,576,670	$211,590	$215,102
6	June	2017	$55,757,840	$30,553,074	$1,890,357	$1,435,692	$16,510,461	$495,314	$204,487,208	$336,684	-$6,896,290	$211,383,498	$253,908	$258,122
7	July	2017	$16,596,483	$134,081	$1,234,680	$1,230,413	$14,149,752	$424,493	$221,512,451	$465,880	-$7,660,823	$229,173,274	$296,225	$301,143
8	August	2017	$15,925,483	$134,081	$1,184,355	$1,230,413	$14,149,752	$424,493	$237,816,369	$504,668	-$8,386,568	$246,202,936	$338,543	$344,163
9	September	2017	$16,239,686	$134,081	$1,207,920	$1,230,413	$14,149,752	$424,493	$254,458,054	$541,813	-$9,075,167	$263,533,222	$380,861	$387,184
10	October	2017	$15,613,483	$134,081	$1,160,955	$1,230,413	$14,149,752	$424,493	$270,426,572	$579,728	-$9,725,853	$280,152,425	$423,179	$430,204
11	November	2017	$54,219,053	$14,896,039	$2,949,226	$3,308,388	$38,046,464	$1,141,394	$325,427,857	$616,109	-$12,418,132	$337,845,989	$465,497	$473,224
12	December	2017	$152,043,883	$52,539,996	$7,462,792	$8,152,015	$93,748,172	$2,812,445	$479,594,961	$741,417	-$19,828,730	$499,423,691	$507,815	$516,245
13	January	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$499,561,203	$1,092,654	-$20,421,702	$519,982,905	$507,815	$516,245
14	February	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$519,527,445	$1,138,143	-$20,969,185	$540,496,630	$507,815	$516,245
15	March	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$539,493,687	$1,183,632	-$21,471,180	$560,964,867	$507,815	$516,245
16	April	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$559,459,929	$1,229,120	-$21,927,686	$581,387,615	$507,815	$516,245
17	May	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$579,426,171	$1,274,609	-$22,338,703	$601,764,874	$507,815	$516,245
18	June	2018	$71,448,148	$17,086,759	$4,077,104	$4,675,079	$53,763,413	$1,612,902	$651,889,246	$1,320,098	-$25,693,684	$677,582,930	$507,815	$516,245
19	July	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$671,855,488	$1,485,189	-$25,894,121	$697,749,609	$507,815	$516,245
20	August	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$691,821,730	$1,530,678	-$26,049,069	$717,870,799	$507,815	$516,245
21	September	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$711,787,972	$1,576,167	-$26,158,528	$737,946,500	$507,815	$516,245
22	October	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$731,754,214	$1,621,656	-$26,222,499	$757,976,713	$507,815	$516,245
23	November	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$751,720,456	$1,667,145	-$26,240,980	$777,961,436	$507,815	$516,245
24	December	2018	$103,959,612	$5,717,664	$7,368,146	$8,448,808	$97,161,286	$2,914,839	$857,514,245	$1,712,633	-$32,977,154	$890,491,399	$507,815	$516,245
25	**13-Month Averages:**								**$634,262,057**			**$658,584,613**		**$516,245**

2) Incentive Plant Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1 C4 10-CWIP L30-53 Unloaded Total Plant Adds	Col 2 C5 10-CWIP L30-53 Prior Period CWIP Closed	Col 3 C6 10-CWIP L30-53 Over Heads Closed to PIS	Col 4 N/A Cost of Removal	Col 5 N/A AFUDC Eligible Plant Additions	Col 6 N/A AFUDC	Col 7 = Prior Month C7 +C1+C3 Incremental Gross Plant	Col 8 = Prior Month C7 * L91/12 Depreciation Accrual	Col 9 = Prior Month C9 - C4 + C8 Reserve	Col 10 =C7-C9 Net Plant	Col 11 Unloaded Low Voltage Additions	Col 12 =C11* (1-L75) * (1+L74+L76) Loaded Low Voltage Additions
26	January	2017	$1,056,402	$908,847	$11,067	$0	$0	$0	$1,067,469	$0	$0	$1,067,469	$0	$0
27	February	2017	$1,350,043	$0	$101,253	$0	$0	$0	$2,518,765	$2,432	$2,432	$2,516,333	$0	$0
28	March	2017	$1,328,768	$0	$99,658	$0	$0	$0	$3,947,190	$5,738	$8,170	$3,939,020	$0	$0
29	April	2017	$32,542,040	$26,336,913	$465,385	$0	$0	$0	$36,954,614	$8,993	$17,163	$36,937,451	$0	$0
30	May	2017	$936,909	$0	$70,268	$0	$0	$0	$37,961,792	$84,193	$101,356	$37,860,435	$0	$0
31	June	2017	$23,124,446	$14,613,775	$638,300	$0	$0	$0	$61,724,538	$86,488	$187,844	$61,536,694	$0	$0
32	July	2017	$2,155,272	$0	$161,645	$0	$0	$0	$64,041,456	$140,626	$328,470	$63,712,985	$0	$0
33	August	2017	$1,484,272	$0	$111,320	$0	$0	$0	$65,637,048	$145,905	$474,375	$65,162,673	$0	$0
34	September	2017	$1,798,476	$0	$134,886	$0	$0	$0	$67,570,410	$149,540	$623,915	$66,946,495	$0	$0
35	October	2017	$1,172,272	$0	$87,920	$0	$0	$0	$68,830,602	$153,945	$777,860	$68,052,743	$0	$0
36	November	2017	$853,384	$0	$64,004	$0	$0	$0	$69,747,991	$156,816	$934,675	$68,813,315	$0	$0
37	December	2017	$4,713,015	$0	$353,476	$0	$0	$0	$74,814,482	$158,906	$1,093,581	$73,720,901	$0	$0
38	January	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$1,264,030	$73,550,452	$0	$0
39	February	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$1,434,478	$73,380,004	$0	$0
40	March	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$1,604,927	$73,209,555	$0	$0
41	April	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$1,775,376	$73,039,106	$0	$0
42	May	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$1,945,825	$72,868,657	$0	$0
43	June	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,116,273	$72,698,209	$0	$0
44	July	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,286,722	$72,527,760	$0	$0
45	August	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,457,171	$72,357,311	$0	$0
46	September	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,627,619	$72,186,863	$0	$0
47	October	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,798,068	$72,016,414	$0	$0
48	November	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$2,968,517	$71,845,965	$0	$0
49	December	2018	$0	$0	$0	$0	$0	$0	$74,814,482	$170,449	$3,138,965	$71,675,517	$0	$0

3) Non-Incentive Plant Forecast (See Note 1)

Line	Forecast Period Month	Year	Col 1 Unloaded Total Plant Adds	Col 2 Prior Period CWIP Closed	Col 3 =(C1-C2)*L74 Over Heads Closed to PIS	Col 4 =(C1-C2+C3)*L75 Cost of Removal	Col 5 =C1-C2+C3-C4 AFUDC Eligible Plant Additions	Col 6 =C5*L76 AFUDC	Col 7 = Prior Month C2 +C2+C5+C6 Incremental Gross Plant	Col 8 = Prior Month C7 * L91/12 Depreciation Accrual	Col 9 = Prior Month C9 - C4 + C8 Incremental Reserve	Col 10 =C7-C9 Net Plant	Col 11 Unloaded Low Voltage Additions	Col 12 =C11* (1-L75) * (1+L74+L76) Loaded Low Voltage Additions
50	January	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$14,708,325	$0	-$1,230,413	$15,938,738	$42,318	$43,020
51	February	2017	$31,772,935	$16,379,141	$1,154,535	$1,323,866	$15,224,462	$456,734	$46,768,661	$33,510	-$2,520,770	$49,289,431	$84,636	$86,041
52	March	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$61,476,986	$106,552	-$3,644,631	$65,121,617	$126,954	$129,061
53	April	2017	$33,332,624	$17,282,137	$1,203,787	$1,380,342	$15,873,932	$476,218	$95,109,272	$140,062	-$4,884,910	$99,994,183	$169,272	$172,082
54	May	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$109,817,597	$216,686	-$5,898,638	$115,716,235	$211,590	$215,102
55	June	2017	$32,633,395	$15,939,299	$1,252,057	$1,435,692	$16,510,461	$495,314	$142,762,671	$250,196	-$7,084,134	$149,846,805	$253,908	$258,122
56	July	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$157,470,995	$325,254	-$7,989,293	$165,460,288	$296,225	$301,143
57	August	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$172,179,320	$358,764	-$8,860,943	$181,040,263	$338,543	$344,163
58	September	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$186,887,645	$392,274	-$9,699,082	$196,586,727	$380,861	$387,184
59	October	2017	$14,441,211	$134,081	$1,073,035	$1,230,413	$14,149,752	$424,493	$201,595,970	$425,783	-$10,503,712	$212,099,682	$423,179	$430,204
60	November	2017	$53,365,669	$14,896,039	$2,885,222	$3,308,388	$38,046,464	$1,141,394	$255,679,866	$459,293	-$13,352,807	$269,032,673	$465,497	$473,224
61	December	2017	$147,330,867	$52,539,996	$7,109,315	$8,152,015	$93,748,172	$2,812,445	$404,780,479	$582,512	-$20,922,311	$425,702,790	$507,815	$516,245
62	January	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$424,746,721	$922,205	-$21,685,731	$446,432,453	$507,815	$516,245
63	February	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$444,712,963	$967,694	-$22,403,664	$467,116,627	$507,815	$516,245
64	March	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$464,679,205	$1,013,183	-$23,076,107	$487,755,312	$507,815	$516,245
65	April	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$484,645,447	$1,058,672	-$23,703,062	$508,348,509	$507,815	$516,245
66	May	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$504,611,689	$1,104,160	-$24,284,527	$528,896,217	$507,815	$516,245
67	June	2018	$71,448,148	$17,086,759	$4,077,104	$4,675,079	$53,763,413	$1,612,902	$577,074,764	$1,149,649	-$27,809,958	$604,884,721	$507,815	$516,245
68	July	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$597,041,006	$1,314,741	-$28,180,843	$625,221,849	$507,815	$516,245
69	August	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$617,007,248	$1,360,229	-$28,506,240	$645,513,488	$507,815	$516,245
70	September	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$636,973,490	$1,405,718	-$28,786,148	$665,759,637	$507,815	$516,245
71	October	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$656,939,732	$1,451,207	-$29,020,567	$685,960,299	$507,815	$516,245
72	November	2018	$19,600,304	$0	$1,470,023	$1,685,626	$19,384,701	$581,541	$676,905,974	$1,496,696	-$29,209,497	$706,115,471	$507,815	$516,245
73	December	2018	$103,959,612	$5,717,664	$7,368,146	$8,448,808	$97,161,286	$2,914,839	$782,699,763	$1,542,185	-$36,116,120	$818,815,883	$507,815	$516,245

4) ISO Corporate Overhead Loader

Line		
74	ISO Corp OH Rate	7.50%

5) ISO Cost of Removal Percent

Line		
75	Cost of Removal Rate	8.00%

6) AFUDC Loader Rate

Line		
76	ISO AFUDC Rate	3.00%

7) Calculation of ISO Depreciation Rate

December Prior Year plant balances and accrual rates are as shown on Schedule 17 Depreciation

Line	Col 1 Acct	Col 2 December Prior Year Plant Balance	Col 3 Accrual Rate	Col 4 C2*C3 Annual Accrual	Accrual Rate Reference
77	**350.1**	$86,845,703	0.00%	$0	18 Dep Rates L1
78	**350.2**	$165,326,927	1.67%	$2,760,960	18 Dep Rates L2
79	**352**	$531,582,611	2.41%	$12,811,141	18 Dep Rates L3
80	**353**	$3,249,175,449	2.84%	$92,276,583	18 Dep Rates L4
81	**354**	$2,233,991,232	2.73%	$60,987,961	18 Dep Rates L5
82	**355**	$324,258,228	2.84%	$9,208,934	18 Dep Rates L6
83	**356**	$1,235,903,790	3.24%	$40,043,283	18 Dep Rates L7
84	**357**	$185,508,197	1.73%	$3,209,292	18 Dep Rates L8
85	**358**	$81,951,072	2.41%	$1,975,021	18 Dep Rates L9
86	**359**	$182,027,087	1.65%	$3,003,447	18 Dep Rates L10
87					
88	Sum of Depreciation Expense			$226,276,620	Sum of C4 Lines 77 to 86
89	Sum of Dec Prior Year Plant			$8,276,570,295	Sum of C2 Lines 77 to 86
90					
91	Composite Depreciation Rate			2.73%	Line 88 / Line 89

Notes:

1) Forecast Period is the calendar year two years after the Prior Year (i.e., PY+2).

2) Sum of Incentive Plant Calculations and Non-Incentive Calculations, lines 26-49 and lines 50-73

Depreciation Expense

Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO

Prior Year: 2016

Balances for Transmission Plant - ISO during the Prior Year, including December of previous year: **Source:** 6-PlantInService, Lines 1-13.

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
		FERC Account:										
Line	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	Dec 2015	$77,976,655	$163,072,480	$470,458,376	$3,030,177,247	$2,164,622,763	$310,678,566	$1,239,646,181	$221,416	$13,011,928	$187,087,541	$7,656,953,152
2	Jan 2016	$77,366,106	$163,089,425	$477,787,637	$3,038,238,129	$2,149,854,075	$312,467,579	$1,241,589,579	$221,419	$13,016,282	$187,350,498	$7,660,980,730
3	Feb 2016	$77,365,696	$163,086,102	$470,257,229	$3,058,743,183	$2,152,015,903	$313,580,382	$1,242,505,439	$221,419	$13,016,547	$187,651,223	$7,678,443,123
4	Mar 2016	$87,298,557	$163,152,630	$476,439,568	$3,076,643,567	$2,150,669,453	$315,593,553	$1,245,422,772	$221,419	$13,020,184	$190,200,199	$7,718,661,901
5	Apr 2016	$87,309,335	$163,197,609	$491,408,710	$3,089,452,188	$2,155,881,434	$316,787,447	$1,245,937,741	$221,425	$14,735,210	$190,592,880	$7,755,523,977
6	May 2016	$87,317,065	$163,204,896	$491,870,167	$3,090,721,159	$2,149,317,764	$317,533,976	$1,246,282,243	$221,425	$15,083,340	$191,019,613	$7,752,571,648
7	Jun 2016	$86,794,533	$162,983,298	$496,064,461	$3,120,246,532	$2,210,512,877	$318,450,055	$1,247,245,617	$221,434	$15,146,687	$192,180,089	$7,849,845,584
8	Jul 2016	$86,801,874	$162,990,137	$501,268,132	$3,170,862,943	$2,212,689,387	$319,127,828	$1,247,320,275	$221,435	$15,149,825	$192,445,155	$7,908,876,992
9	Aug 2016	$86,799,926	$163,006,399	$501,046,195	$3,171,072,527	$2,228,283,811	$319,715,189	$1,241,488,154	$221,437	$15,146,092	$178,450,654	$7,905,230,384
10	Sep 2016	$86,814,704	$165,199,257	$502,725,446	$3,174,643,082	$2,227,591,400	$320,439,816	$1,245,055,136	$178,517,523	$77,483,575	$178,430,166	$8,156,900,104
11	Oct 2016	$86,813,903	$165,297,497	$517,665,602	$3,188,871,202	$2,231,665,227	$321,310,132	$1,251,456,010	$180,892,151	$80,351,534	$179,079,774	$8,203,403,034
12	Nov 2016	$86,821,377	$165,325,104	$520,661,331	$3,201,337,814	$2,220,025,052	$322,121,103	$1,251,410,453	$184,358,841	$81,550,530	$179,287,045	$8,212,898,650
13	Dec 2016	$86,845,703	$165,326,927	$531,582,611	$3,249,175,449	$2,233,991,232	$324,258,228	$1,235,903,790	$185,508,197	$81,951,072	$182,027,087	$8,276,570,295
14												

15 Depreciation Rates (Percent per year) See "18-DepRates" and Instruction 1.

16	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
17a	Dec 2015	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17b	Jan 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17c	Feb 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17d	Mar 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17e	Apr 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17f	May 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17g	Jun 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17h	Jul 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17i	Aug 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17j	Sep 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17k	Oct 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17l	Nov 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%
17m	Dec 2016	0.00%	1.66%	2.57%	2.47%	2.44%	3.67%	3.05%	1.65%	3.87%	1.56%

18

19 Monthly Depreciation Expense for Transmission Plant - ISO by FERC Account: See Note 1 and Instruction 1

20

21		FERC										
22		Account:										Month
23	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
24	Jan 2016	$0	$225,584	$1,007,565	$6,237,115	$4,401,400	$950,159	$3,150,767	$304	$41,963	$243,214	$16,258,071
25	Feb 2016	$0	$225,607	$1,023,262	$6,253,707	$4,371,370	$955,630	$3,155,707	$304	$41,978	$243,556	$16,271,120
26	Mar 2016	$0	$225,602	$1,007,134	$6,295,913	$4,375,766	$959,033	$3,158,035	$304	$41,978	$243,947	$16,307,713
27	Apr 2016	$0	$225,694	$1,020,375	$6,332,758	$4,373,028	$965,190	$3,165,450	$304	$41,990	$247,260	$16,372,050
28	May 2016	$0	$225,757	$1,052,434	$6,359,122	$4,383,626	$968,842	$3,166,758	$304	$47,521	$247,771	$16,452,135
29	Jun 2016	$0	$225,767	$1,053,422	$6,361,734	$4,370,279	$971,125	$3,167,634	$304	$48,644	$248,325	$16,447,235
30	Jul 2016	$0	$225,460	$1,062,405	$6,422,507	$4,494,710	$973,926	$3,170,083	$304	$48,848	$249,834	$16,648,078
31	Aug 2016	$0	$225,470	$1,073,549	$6,526,693	$4,499,135	$975,999	$3,170,272	$304	$48,858	$250,179	$16,770,460
32	Sep 2016	$0	$225,492	$1,073,074	$6,527,124	$4,530,844	$977,796	$3,155,449	$304	$48,846	$231,986	$16,770,915
33	Oct 2016	$0	$228,526	$1,076,670	$6,534,474	$4,529,436	$980,012	$3,164,515	$245,462	$249,885	$231,959	$17,240,938
34	Nov 2016	$0	$228,662	$1,108,667	$6,563,760	$4,537,719	$982,673	$3,180,784	$248,727	$259,134	$232,804	$17,342,930
35	Dec 2016	$0	$228,700	$1,115,083	$6,589,420	$4,514,051	$985,154	$3,180,668	$253,493	$263,000	$233,073	$17,362,643
36	Totals:	$0	$2,716,320	$12,673,640	$77,004,328	$53,381,363	$11,645,539	$37,986,122	$750,422	$1,182,645	$2,903,907	
37								Total Annual Depreciation Expense for Transmission Plant - ISO:				$200,244,286
38								(equals sum of monthly amounts)				

39 2) Calculation of Depreciation Expense for Distribution Plant - ISO

Line						
40						
41		**360**	**361**	**362**		**Source**
42	Distribution Plant - ISO BOY	$0	$0	$0		6-PlantInService Line 15.
43	Distribution Plant - ISO EOY	$0	$0	$0		6-PlantInService Line 16.
44	Average BOY/EOY :	$0	$0	$0		
45						
46	Depreciation Rates (Percent per year) See "18-DepRates".					
47		**360**	**361**	**362**		
48		1.67%	2.39%	2.01%		
49						
50	Depreciation Expense for Distribution Plant - ISO		See Note 2 and Instruction 2			
51						
52		**360**	**361**	**362**	**Total**	
53		$0	$0	$0	$0	Total is sum of Depreciation Expense for accounts
54						360, 361, and 362
55						

56 3) Calculation of Depreciation Expense for General Plant and Intangible Plant

Line			
57			
58	Total General Plant Depreciation Expense	234,519,750	FF1 336.10f
59	Total Intangible Plant Depreciation Expense	254,773,828	FF1 336.1f
60	Sum of Total General and Total Intangible Depreciation Expense	$489,293,578	Line 58 + Line 59
61	Transmission Wages and Salaries Allocation Factor	6.1650%	27-Allocators, Line 9
62	General and Intangible Depreciation Expense	$30,164,956	Line 60 * Line 61
63			

64 4) Depreciation Expense

Line			
65			
66	Depreciation Expense is the sum of:	**Amount**	**Source**
67	1) Depreciation Expense for Transmission Plant - ISO	$200,244,286.19	Line 37, Col 12
68	2) Depreciation Expense for Distribution Plant - ISO	$0	Line 53
69	3) General and Intangible Depreciation Expense	$30,164,956	Line 62
70	Depreciation Expense:	$230,409,241.71	Line 67 + Line 68 + Line 69

Notes:

1) Depreciation Expense for each account for each month is equal to the previous month balance of Transmission Plant - ISO for that same account, times the Monthly Depreciation Rate for that account. Monthly rate = annual rates on Line 17a etc. divided by 12.

2) Depreciation Expense for each account is equal to the Average BOY/EOY value on Line 44 times the Depreciation Rate on Line 48.

Instructions:

1) Depreciation rates on Lines 17a-17m input from Schedule 18. However, in the event of a change in depreciation rates approved by the Commission, use Commission-approved depreciation rates that were in effect during the Prior Year.

2) In the event that depreciation rates stated on Schedule 18 to be applied to Distribution Plant - ISO are revised mid-year, calculate Depreciation Expense for for Distribution Plant - ISO on Line 53 utilizing the weighted-average (by time) of the annual depreciation rates in effect in the Prior Year.

Depreciation Rates

1) Transmission Plant - ISO

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
1	350.1	Fee Land	0.00%	0.00%	0.00%
2	350.2	Easements	1.67%	0.00%	1.67%
3	352	Structures and Improvements	1.79%	0.62%	2.41%
4	353	Station Equipment	2.39%	0.45%	2.84%
5	354	Towers and Fixtures	1.20%	1.53%	2.73%
6	355	Poles and Fixtures	1.06%	1.78%	2.84%
7	356	Overhead Conductors and Devices	0.78%	2.46%	3.24%
8	357	Underground Conduit	1.73%	0.00%	1.73%
9	358	Underground Conductors and Devices	1.62%	0.79%	2.41%
10	359	Roads and Trails	1.65%	0.00%	1.65%
11					

2) Distribution Plant - ISO

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
12	360	Land and Land Rights	1.67%	0.00%	1.67%
13	361	Structures and Improvements	1.75%	0.64%	2.39%
14	362	Station Equipment	1.32%	0.69%	2.01%

3) General Plant

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
15	389	Land and Land Rights	1.67%	0.00%	1.67%
16	390	Structures and Improvements	1.81%	0.27%	2.08%
17	391.1	Office Furniture	5.00%	0.00%	5.00%
18	391.5	Office Equipment	20.00%	0.00%	20.00%
19	391.6	Duplicating Equipment	20.00%	0.00%	20.00%
20	391.2	Personal Computers	20.00%	0.00%	20.00%
21	391.3	Mainframe Computers	20.00%	0.00%	20.00%
22	391.7	PC Software	20.00%	0.00%	20.00%
23	391.4	DDSMS - CPU & Processing	14.29%	0.00%	14.29%
24	391.4	DDSMS - Controllers, Receivers, Comm.	10.00%	0.00%	10.00%
25	391.4	DDSMS - Telemetering & System	6.67%	0.00%	6.67%
26	391.4	DDSMS - Miscellaneous	5.00%	0.00%	5.00%
27	391.4	DDSMS - Map Board	4.00%	0.00%	4.00%
28	393	Stores Equipment	5.00%	0.00%	5.00%
29	395	Laboratory Equipment	6.67%	0.00%	6.67%
30	398	Misc Power Plant Equipment	5.00%	0.00%	5.00%
31	397	Data Network Systems	20.00%	0.00%	20.00%
32	397	Telecom System Equipment	14.29%	0.00%	14.29%
33	397	Netcomm Radio Assembly	10.00%	0.00%	10.00%
34	397	Microwave Equip. & Antenna Assembly	6.67%	0.00%	6.67%
35	397	Telecom Power Systems	5.00%	0.00%	5.00%
36	397	Fiber Optic Communication Cables	4.00%	0.00%	4.00%
37	397	Telecom Infrastructure	2.50%	0.00%	2.50%
38	392	Transportation Equip.	14.29%	0.00%	14.29%
39	394.4	Garage & Shop -- Equip.	10.00%	0.00%	10.00%
40	394.5	Tools & Work Equip. -- Shop	10.00%	0.00%	10.00%
41	396	Power Oper Equip	6.67%	0.00%	6.67%

4) Intangible Plant

Line	FERC Account	Description	Plant Less Salvage	Removal Cost	Total
42	302	Hydro Relicensing	2.47%	0.00%	2.47%
43	303	Radio Frequency	2.50%	0.00%	2.50%
44	301	Other Intangibles	5.00%	0.00%	5.00%
45	303	Cap Soft 5yr	20.31%	0.00%	20.31%
46	303	Cap Soft 7yr	14.62%	0.00%	14.62%
47	303	Cap Soft 10yr	12.93%	0.00%	12.93%
48	303	Cap Soft 15yr	8.48%	0.00%	8.48%

Operations and Maintenance Expenses

Cells shaded yellow are input cells

1) Determination of Adjusted Operations and Maintenance Expenses for each account (Note 1)

	Col 1	Col 2 = C3 + C4	Col 3	Col 4	Col 5 Note 2	Col 6 = C7 + C8	Col 7	Col 8	Col 9 = C10 + C11	Col 10 = C3 + C7	Col 11 = C4 + C8
		Total Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor
Line	**Transmission Accounts**										
1	560 - Operations Supervision and Engineering - Allocated	$9,662,716	$4,478,898	$5,183,817		$0	$0	$0	9,662,716	4,478,898	5,183,817
2	560 - Sylmar/Palo Verde	$211,155	$0	$211,155		$0	$0	$0	211,155	-	211,155
3	561 Load Dispatch - Allocated	$10,284,005	$8,327,930	$1,956,075		$0	$0	$0	10,284,005	8,327,930	1,956,075
4	561.400 Scheduling, System Control and Dispatch Services	$37,337,693	$0	$37,337,693	A	-$37,337,693	$0	($37,337,693)	-	-	-
5	561.500 Reliability Planning and Standards Development	$4,998,172	$4,185,120	$813,052		$0	$0	$0	4,998,172	4,185,120	813,052
6	562 - Station Expenses - Allocated	$22,535,988	$18,184,794	$4,351,194		$0	$0	$0	22,535,988	18,184,794	4,351,194
7	562 - MOGS Station Expense	$0	$0	$0		$0	$0	$0	-	-	-
8	562 - Sylmar/Palo Verde	$1,003,580	$84	$1,003,496		$0	$0	$0	1,003,580	84	1,003,496
9	563 - Overhead Line Expenses - Allocated	$6,707,716	$3,569,599	$3,138,117		$0	$0	$0	6,707,716	3,569,599	3,138,117
10	564 - Underground Line Expenses - Allocated	$1,182,483	$968,761	$213,722		$0	$0	$0	1,182,483	968,761	213,722
11	565 - Transmission of Electricity by Others	$5,830,496	$0	$5,830,496		$0	$0	$0	5,830,496	-	5,830,496
12	565 - Wheeling Costs	$11,062,097	$0	$11,062,097	C	-$11,062,097	$0	($11,062,097)	-	-	-
13	565 - WAPA Transmission for Remote Service	$242,798	$0	$242,798		$0	$0	$0	242,798	-	242,798
14	566 - Miscellaneous Transmission Expenses - Allocated	$47,043,938	$22,105,385	$24,938,553	F	-$43,078	$0	($43,078)	47,000,860	22,105,385	24,895,475
15	566 - ISO/RSBA/TSP Balancing Accounts	-$31,308,784	$136,682	($31,445,466)	D	$31,308,784	($136,682)	$31,445,466	-	-	-
16	566 - Sylmar/Palo Verde/Other General Functions	$1,048,641	$0	$1,048,641		$0	$0	$0	1,048,641	-	1,048,641
17	567 - Line Rents - Allocated	$15,840,955	$5,281	$15,835,675		$0	$0	$0	15,840,955	5,281	15,835,675
18	567 - Eldorado	$49,557	$0	$49,557		$0	$0	$0	49,557	-	49,557
19	567 - Sylmar/Palo Verde	$355,202	$0	$355,202		$0	$0	$0	355,202	-	355,202
20	568 - Maintenance Supervision and Engineering - Allocated	$2,115,851	$1,858,978	$256,873		$0	$0	$0	2,115,851	1,858,978	256,873
21	568 - Sylmar/Palo Verde	$212,545	$0	$212,545		$0	$0	$0	212,545	-	212,545
22	569 - Maintenance of Structures - Allocated	$37,576,147	$70,184	$37,505,963	E	-$36,772,403	$0	($36,772,403)	803,744	70,184	733,560
23	569 - Sylmar/Palo Verde	$183,311	$0	$183,311		$0	$0	$0	183,311	-	183,311
24	570 - Maintenance of Station Equipment - Allocated	$10,701,931	$5,504,648	$5,197,283		$0	$0	$0	10,701,931	5,504,648	5,197,283
25	570 - Sylmar/Palo Verde	$1,489,321	$38	$1,489,283		$0	$0	$0	1,489,321	38	1,489,283
26	571 - Maintenance of Overhead Lines - Allocated	$27,242,929	$7,762,802	$19,480,126	F	-$950,473	($6,930)	($943,543)	26,292,456	7,755,873	18,536,583
27	571 - Sylmar/Palo Verde	$181,120	$0	$181,120		$0	$0	$0	181,120	-	181,120
28	572 - Maintenance of Underground Lines - Allocated	$257,494	$112,517	$144,977		$0	$0	$0	257,494	112,517	144,977
29	572 - Sylmar/Palo Verde	$6,519	$0	$6,519		$0	$0	$0	6,519	-	6,519
30	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$3,685,780	$1,205,500	$2,480,280		$0	$0	$0	3,685,780	1,205,500	2,480,280
31	…	---	---	---	---	$0	---	---			
32	Transmission NOIC (Note 3)	-	-	-		$9,522,010	$9,522,010	$0	$9,522,010	$9,522,010	$0
33	**Total Transmission O&M**	$227,741,354	$78,477,202	$149,264,152		-$45,334,951	$9,378,398	-$54,713,349	$182,406,403	$87,855,599	$94,550,803
34											

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
		= C3 + C4			Note 2	= C7 + C8			= C10 + C11	= C3 + C7	= C4 + C8
		Total Recorded O&M Expenses			Adjustments				Adjusted Recorded O&M Expenses		
	Account/Work Activity Rev	Total	Labor	Non-Labor	Reason	Total	Labor	Non-Labor	Total	Labor	Non-Labor
	Distribution Accounts										
35	582 - Station Expenses	33,377,982	$25,670,085	$7,707,897		-	$0	$0	33,377,982	25,670,085	7,707,897
36	590 - Maintenance Supervision and Engineering	2,112,515	$1,853,871	$258,644		-	$0	$0	2,112,515	1,853,871	258,644
37	591 - Maintenance of Structures	133,488	$14,746	$118,742		-	$0	$0	133,488	14,746	118,742
38	592 - Maintenance of Station Equipment	9,319,393	$5,105,567	$4,213,827		-	$0	$0	9,319,393	5,105,567	4,213,827
39	Accounts with no ISO Distribution Costs	478,484,086	$195,853,819	$282,630,267	F	(4,772,028)	($354,623)	($4,417,405)	473,712,058	195,499,196	278,212,862
40	Distribution NOIC (Note 3)	-	-	-		27,724,752	27,724,752	-	27,724,752	27,724,752	-
41	**Total Distribution O&M**	523,427,463	228,498,087	294,929,376		22,952,724	27,370,129	(4,417,405)	546,380,187	255,868,216	290,511,971
42											
43	**Total Transmission and Distribution O&M**	751,168,817	306,975,289	444,193,529		(22,382,227)	36,748,527	(59,130,754)	728,786,590	343,723,816	385,062,775
44											
45	Total Transmission O&M Expenses in FERC Form 1:	$227,741,355	FF1 321.112b	Must equal Line 33, Column 2.							
46	Total Distribution O&M Expenses in FERC Form 1:	$523,427,463	FF1322.156b	Must equal Line 41, Column 2.							
47	Total TDBU NOIC	$37,246,762	20-AandG, Note 2, f								

2) Determination of ISO Operations and Maintenance Expenses for each account (Note 5).

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**ISO**	**Total**	**Labor**	**Non-Labor**	**Reference**
Line	**Transmission Accounts**								
48	560 - Operations Supervision and Engineering - Allocated	9,662,716	4,478,898	5,183,817	36.3%	3,507,252	1,625,695	1,881,557	27-Allocators Line 42
49	560 - Sylmar/Palo Verde	211,155	-	211,155	100.0%	211,155	-	211,155	100%
50	561 Load Dispatch - Allocated	10,284,005	8,327,930	1,956,075	36.3%	3,732,759	3,022,768	709,992	27-Allocators Line 42
51	561.400 Scheduling, System Control and Dispatch Services	-	-	-	0.0%	-	-	-	0%
52	561.500 Reliability Planning and Standards Development	4,998,172	4,185,120	813,052	100.0%	4,998,172	4,185,120	813,052	100%
53	562 - Station Expenses - Allocated	22,535,988	18,184,794	4,351,194	36.3%	8,179,831	6,600,489	1,579,342	27-Allocators Line 42
54	562 - MOGS Station Expense	-	-	-	0.0%	-	-	-	0%
55	562 - Sylmar/Palo Verde	1,003,580	84	1,003,496	100.0%	1,003,580	84	1,003,496	100%
56	563 - Overhead Line Expenses - Allocated	6,707,716	3,569,599	3,138,117	46.7%	3,134,239	1,667,926	1,466,313	27-Allocators Line 30
57	564 - Underground Line Expenses - Allocated	1,182,483	968,761	213,722	1.4%	16,622	13,618	3,004	27-Allocators Line 36
58	565 - Transmission of Electricity by Others	5,830,496	-	5,830,496	100.0%	5,830,496	-	5,830,496	100%
59	565 - Wheeling Costs	-	-	-	0.0%	-	-	-	0%
60	565 - WAPA Transmission for Remote Service	242,798	-	242,798	0.0%	-	-	-	0%
61	566 - Miscellaneous Transmission Expenses - Allocated	47,000,860	22,105,385	24,895,475	36.3%	17,059,785	8,023,536	9,036,248	27-Allocators Line 42
62	566 - ISO/RSBA/TSP Balancing Accounts	-	-	-	0.0%	-	-	-	0%
63	566 - Sylmar/Palo Verde/Other General Functions	1,048,641	-	1,048,641	100.0%	1,048,641	-	1,048,641	100%
64	567 - Line Rents - Allocated	15,840,955	5,281	15,835,675	46.7%	7,401,825	2,467	7,399,358	27-Allocators Line 30
65	567 - Eldorado	49,557	-	49,557	100.0%	49,557	-	49,557	100%
66	567 - Sylmar/Palo Verde	355,202	-	355,202	100.0%	355,202	-	355,202	100%
67	568 - Maintenance Supervision and Engineering - Allocated	2,115,851	1,858,978	256,873	36.3%	767,985	674,749	93,237	27-Allocators Line 42
68	568 - Sylmar/Palo Verde	212,545	-	212,545	100.0%	212,545	-	212,545	100%
69	569 - Maintenance of Structures - Allocated	803,744	70,184	733,560	36.3%	291,733	25,475	266,258	27-Allocators Line 42
70	569 - Sylmar/Palo Verde	183,311	-	183,311	100.0%	183,311	-	183,311	100%
71	570 - Maintenance of Station Equipment - Allocated	10,701,931	5,504,648	5,197,283	36.3%	3,884,453	1,998,009	1,886,445	27-Allocators Line 42
72	570 - Sylmar/Palo Verde	1,489,321	38	1,489,283	100.0%	1,489,321	38	1,489,283	100%
73	571 - Maintenance of Overhead Lines - Allocated	26,292,456	7,755,873	18,536,583	46.7%	12,285,380	3,623,999	8,661,381	27-Allocators Line 30
74	571 - Sylmar/Palo Verde	181,120	-	181,120	100.0%	181,120	-	181,120	100%
75	572 - Maintenance of Underground Lines - Allocated	257,494	112,517	144,977	1.4%	3,620	1,582	2,038	27-Allocators Line 36
76	572 - Sylmar/Palo Verde	6,519	-	6,519	100.0%	6,519	-	6,519	100%
77	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	3,685,780	1,205,500	2,480,280	36.3%	1,337,818	437,557	900,261	27-Allocators Line 42
78	…	---	---	---	---	---	---	---	
79	Transmission NOIC (Note 4)	9,522,010	9,522,010	-		3,878,052	3,878,052	-	
80	**Total Transmission - ISO O&M**	182,406,403	87,855,599	94,550,803		81,050,973	35,781,164	45,269,809	
81									

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9
		From C9 above	From C10 above	From C11 above	Note 6	= C7 + C8	= C3 * C5	= C4 * C5	
		Adjusted Recorded O&M Expenses			Percent	ISO O&M Expenses			Percent ISO
	Account/Work Activity Rev	**Total**	**Labor**	**Non-Labor**	**ISO**	**Total**	**Labor**	**Non-Labor**	**Reference**
	Distribution Accounts								
82	582 - Station Expenses	33,377,982	25,670,085	7,707,897	0.0%	-	-	-	27-Allocators Line 48
83	590 - Maintenance Supervision and Engineering	2,112,515	1,853,871	258,644	0.0%	-	-	-	27-Allocators Line 48
84	591 - Maintenance of Structures	133,488	14,746	118,742	0.0%	-	-	-	27-Allocators Line 48
85	592 - Maintenance of Station Equipment	9,319,393	5,105,567	4,213,827	0.0%	-	-	-	27-Allocators Line 48
86	Accounts with no ISO Distribution Costs	473,712,058	195,499,196	278,212,862	0.00%	-	-	-	0%
87	Distribution NOIC (Note 4)	27,724,752	27,724,752	-	0.00%	-	-	-	0%
88	**Total Distribution - ISO O&M**	546,380,187	255,868,216	290,511,971		-	-	-	
89									
90									
91	**Total ISO O&M Expenses (in Column 6)**	728,786,590	343,723,816	385,062,775		81,050,973	35,781,164	45,269,809	
92	Line 80 + Line 88								

Notes:

1) "Adjusted Operations and Maintenance Expenses for each account" are the total amounts of O&M costs booked to each Transmission or Distribution account, less adjustments as noted.

2) Reasons for excluded amounts:

A: Exclude entire amount, all attributable to CAISO costs recovered in Energy Resource Recovery Account.
B: Exclude amount related to MOGS Station Expense.
C: Exclude amount attributable to CAISO costs recovered in Energy Resource Recovery Account.
D: Exclude amount recovered through to Reliability Services Balancing Account, the Transmission Access Charge Balancing Account Adjustment, and the American Reinvestment Recovery Act for the Tehachapi Wind Energy Storage Project.
E: Exclude amount of costs transfered to account from A&G Account 920 pursuant to Order 668.
F: Excludes shareholder funded costs.

3) Total TDBU NOIC is allocated to Transmission and Distribution in proportion to labor in the respective functions. Transmission NOIC ("Non-Officer Incentive Compensation") equals Total TDBU NOIC times the Transmission NOIC Percentage calculated below. Distribution NOIC equals Total TDBU NOIC times the Distribution NOIC Percentage below.

Total TDBU NOIC is on Line: 47

	Percentage	Calculation
Transmission NOIC Percentage:	25.5647%	Line 33, Col 3 / Line 43, Col 3
Distribution NOIC Percentage:	74.4353%	Line 41, Col 3 / Line 43, Col 3

4) NOIC attributable to ISO Transmission (Column 7) is calculated utilizing a percentage equal to the ratio of total ISO O&M Labor Expenses in column 7 (exclusive of NOIC) to the total labor expenses in column 3 (exclusive of NOIC). That allocator, which is identified below, is then applied to the value in Column 3 to arrive at the NOIC attributable to ISO Transmission in Column 7.
Resulting Percentage is: 40.73%

5) "ISO Operations and Maintenance Expenses" is the amount of costs in each Transmission or Distribution account related to ISO Transmission Facilities.

6) See Column 9 for references to source of each Percent ISO.

7) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 19.

Calculation of Administrative and General Expense

Inputs are shaded yellow

Line	Acct.	Description	Col 1 FERC Form 1 Amount	Col 2 Data Source	Col 3 See Note 1 Total Amount Excluded	Col 4 A&G Expense	Notes
1	920	A&G Salaries	$370,948,767	FF1 323.181b	$55,730,842	$315,217,925	
2	921	Office Supplies and Expenses	$213,803,210	FF1 323.182b	$409,079	$213,394,131	
3	922	A&G Expenses Transferred	-$119,273,668	FF1 323.183b	-$29,401,382	-$89,872,286	Credit
4	923	Outside Services Employed	$60,667,969	FF1 323.184b	$7,725,398	$52,942,571	
5	924	Property Insurance	$14,124,920	FF1 323.185b	$0	$14,124,920	
6	925	Injuries and Damages	$90,935,394	FF1 323.186b	$0	$90,935,394	
7	926	Employee Pensions and Benefits	$169,577,000	FF1 323.187b	-$23,052,226	$192,629,226	
8	927	Franchise Requirements	$104,853,533	FF1 323.188b	$104,853,533	$0	
9	928	Regulatory Commission Expenses	$39,330,186	FF1 323.189b	$40,447,590	-$1,117,404	
10	929	Duplicate Charges	$0	FF1 323.190b	$0	$0	
11	930.1	General Advertising Expense	$4,740,534	FF1 323.191b	$0	$4,740,534	
12	930.2	Miscellaneous General Expense	$18,871,749	FF1 323.192b	$22,065,926	-$3,194,177	
13	931	Rents	$17,771,530	FF1 323.193b	$0	$17,771,530	
14	935	Maintenance of General Plant	$13,400,370	FF1 323.196b	$718,532	$12,681,838	
15			$999,751,494		Total A&G Expenses:	$820,254,201	

Line		Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	$820,254,201	Line 15
17	Less Account 924:	$14,124,920	Line 5
18	Amount to apply the Transmission W&S AF:	$806,129,281	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	6.1650%	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	$49,697,881	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	19.3143%	27-Allocators, Line 22
22	Property Insurance portion of A&G:	$2,728,124	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$52,426,004	Line 20 + Line 22

Note 1: Itemization of exclusions

Line	Acct.	Total Amount Excluded (Sum of Col 1 to Col 4)	Col 1 Shareholder Exclusions or Other Adjustments	Col 2 Franchise Requirements	Col 3 NOIC	Col 4 PBOPs	Notes
24	920	$55,730,842	-$29,416,675		$85,147,517		See Instructions 2b, 3, and Note 2
25	921	$409,079	$409,079		$0		
26	922	-$29,401,382	-$7,665,955		-$21,735,427		
27	923	$7,725,398	$7,725,398		$0		
28	924	$0	$0		$0		
29	925	$0	$0		$0		
30	926	-$23,052,226	-$9,115,141		$0	-$13,937,085	See Note 3
31	927	$104,853,533	$0	$104,853,533	$0	$0	See Note 4
32	928	$40,447,590	$40,447,590		$0		
33	929	$0	$0		$0		
34	930.1	$0	$0		$0		
35	930.2	$22,065,926	$22,065,926		$0		
36	931	$0	$0		$0		
37	935	$718,532	$718,532		$0		

Note 2: Non-Officer Incentive Compensation ("NOIC") Adjustment

Adjust NOIC by excluding accrued NOIC Amount and replacing with the actual non-capitalized A&G NOIC payout.

		Amount	Source
a	Accrued NOIC Amount:	$108,677,133	SCE Records
b	Actual A&G NOIC payout:	$23,529,616	Note 2, d
c	Adjustment:	$85,147,517	

Actual non-capitalized NOIC Payouts:

	Department		Amount	Source
d	A&G		$23,529,616	SCE Records and Workpapers
e	Other		$11,215,512	SCE Records and Workpapers
f	Trans. And Dist. Business Unit		$37,246,762	SCE Records and Workpapers
g		Total:	$71,991,890	Sum of d to f

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
a	Current Authorized PBOPs Expense Amount:	$40,171,333	See instruction #4
b	Prior Year Authorized PBOPs Expense Amount:	$37,714,779	Authorized PBOPs Expense Amount during Prior Year
c	Prior Year FF1 PBOPs expense:	$23,777,694	SCE Records
d	PBOPs Expense Exclusion:	-$13,937,085	c - b

Note 4:

Amount in Line 31, column 2 equals amount in Line 8, column 1 because all Franchise Requirements Expenses are excluded Franchise Fees Expenses component of the Prior Year TRR are based on Franchise Fee Factors.

Instructions:

1) Enter amounts of A&G expenses from FERC Form 1 in Lines 1 to 14.
2) Fill out "Itemization of Exclusions" table for all input cells. NOIC amount in Column 3, Line 24
is calculated in Note 2. The PBOPs exclusion in Column 4, Line 30 is calculated in Note 3.
   a) Exclude amount of any Shareholder Adjustments, costs incurred on behalf of SCE shareholders, from relevant account in Column 1.
   b) Include as an adjustment in Column 1 for Account 920 any amount excluded from Accounts 569.100, 569.200, and 569.300 in Schedule 19 (OandM) related to Order 668 costs transferred.
   c) Exclude entire amount of account 927 "Franchise Requirements" in Column 2, as those costs are recovered through the Franchise Fees Expense item.
   d) Exclude any amount of Account 930.1 "General Advertising Expense" not related to advertising for safety, siting, or informational purposes in column 1.
   e) Exclude any amount of expense relating to secondary land use and audit expenses not directly benefitting utility customers.
   f) Exclude from account 930.2:
      1) Nuclear Power Research Expenses.
      2) Write Off of Abandoned Project Expenses.
      3) Any advertising expenses within the Consultants/Professional Services category.
   g) Exclude the following costs included in any account 920-935:
      1) Any amount of "Provision for Doubtful Accounts" costs.
      2) Any amount of "Accounting Suspense" costs.
      3) Any penalties or fines.
      4) Any amount of costs recovered 100% through California Public Utilities Commission ("CPUC") rates.
3) NOIC adjustment in Column 3**,** Line 24 is made by determining the difference between the total accrued NOIC amount included in the FERC Form 1 recorded cost amounts and the actual A&G NOIC payout (see note 2).
NOIC adjustment in column 3, Line 26 is made by entering the amount of accrued NOIC that is capitalized.
4) Determine the PBOPs exclusion. The authorized amount of PBOPs expense (line a) may only be revised pursuant to Commission acceptance of an SCE FPA Section 205 filing to revise the authorized PBOPs expense, in accordance with the tariff protocols. Accordingly, any amount different than the authorized PBOPs expense during the Prior Year is excluded from account 926 (see note 3). Docket or Decision approving authorized PBOPs amount: ER16-2433
5) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 20.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
1a	450	4191110	Late Payment Charge- Comm. & Ind.	5,497,690	Traditional OOR	5,497,690	0	5,497,690	0			0	0	1
1b	450	4191115	Residential Late Payment	10,731,849	Traditional OOR	10,731,849	0	10,731,849	0			0	0	1
2	450 Total			16,229,538		16,229,538	0	16,229,538	0		0	0	0	
3	FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)			16,229,538										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	141,269	Traditional OOR	141,269	0	141,269	0			0	0	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	581,923	Traditional OOR	581,923	0	581,923	0			0	0	1
4c	451	4192110	Miscellaneous Service Revenues	124,032,620	Traditional OOR	124,032,620	0	124,032,620	0			0	0	1
4d	451	4192115	Returned Check Charges	1,330,081	Traditional OOR	1,330,081	0	1,330,081	0			0	0	1
4e	451	4192125	Service Reconnection Charges	6,931	Traditional OOR	6,931	0	6,931	0			0	0	1
4f	451	4192130	Service Establishment Charge	(41)	Traditional OOR	(41)	0	(41)	0			0	0	1
4g	451	4192140	Field Collection Charges	34	Traditional OOR	34	0	34	0			0	0	1
4h	451	4192510	Quickcheck Revenue	61	GRSM	0	0	0	61	P	15	46	0	2
4i	451	4192910	PUC Reimbursement Fee-Elect	329,733	Other Ratemaking	0	0	0	0			0	329,733	6
4j	451	4182120	Uneconomic Line Extension	2,587	Traditional OOR	2,587	0	2,587	0			0	0	1
4k	451	4192152	Opt Out CARE-Res-Ini	1,770	Other Ratemaking	0	0	0	0			0	1,770	1
4l	451	4192155	Opt Out CARE-Res-Mo	65,755	Other Ratemaking	0	0	0	0			0	65,755	1
4m	451	4192158	Opt Out NonCARE-Res-Ini	50,925	Other Ratemaking	0	0	0	0			0	50,925	1
4n	451	4192160	Opt Out NonCARE-Res-Mo	464,105	Other Ratemaking	0	0	0	0			0	464,105	1
4o	451	4192135	Conn-Charge - Residential	5,808,217	Traditional OOR	5,808,217	0	5,808,217	0			0	0	1
4p	451	4192145	Conn-Charge - Non-Residential	2,197,297	Traditional OOR	2,197,297	0	2,197,297	0			0	0	1
4q	451	4192150	Conn-Charge - At Pole	20,732	Traditional OOR	20,732	0	20,732	0			0	0	1
5	451 Total			135,033,999		134,121,650	0	134,121,650	61		15	46	912,288	
6	FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)			135,033,999										
8	453 Total			0		0	0	0	0		0	0	0	
9	FF-1 Total for Acct 453 - Sales of Water and Power, p300.18b (Must Equal Line 8)													
10a	454	4184110	Joint Pole - Tariffed Conduit Rental	519,853	Traditional OOR	519,853	0	519,853	0			0	0	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	3,323,162	Traditional OOR	3,323,162	0	3,323,162	0			0	0	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	599,120	Traditional OOR	599,120	0	599,120	0			0	0	4
10d	454	4184120	Joint Pole - Aud - Unauth Penalty	421,500	Traditional OOR	421,500	0	421,500	0			0	0	4
10e	454	4184510	Joint Pole - Non-Tariffed Pole Rental	134,803	GRSM	0	0	0	134,803	P	28,370	106,432	0	2
10f	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	43,296	GRSM	0	0	0	43,296	P	17,760	25,536	0	2
10g	454	4184514	Joint Pole - Non-Tariff Requests for Information	(640)	GRSM	0	0	0	(640)	P	(465)	(175)	0	2
10h	454	4184516	Oil And Gas Royalties	9,990	GRSM	0	0	0	9,990	P	2,634	7,355	0	2
10i	454	4184518	Def Operating Land & Facilities Rent Rev	(168,171)	Traditional OOR	(168,171)	0	(168,171)	0			0	0	4
10j	454	4184810	Facility Cost -EIX/Nonutility	268,319	Other Ratemaking	15,882	15,882	0	0			0	252,437	6, 12
10k	454	4184815	Facility Cost- Utility		Traditional OOR	0	0	0	0			0	0	7
10l	454	4184820	Rent Billed to Non-Utility Affiliates	1,478,793	Other Ratemaking	87,530	87,530	0	0			0	1,391,263	6, 12
10m	454	4184825	Rent Billed to Utility Affiliates		Traditional OOR	0	0	0	0			0	0	7
10n	454	4194110	Meter Leasing Revenue		Traditional OOR	0	0	0	0			0	0	1
10o	454	4194115	Company Financed Added Facilities	10,732,510	Traditional OOR	10,732,510	0	10,732,510	0			0	0	4
10p	454	4194120	Company Financed Interconnect Facilities	662,750	Traditional OOR	662,750	0	662,750	0			0	0	4
10q	454	4194130	SCE Financed Added Faclty	23,706,989	Traditional OOR	23,706,989	0	23,706,989	0			0	0	4
10r	454	4194135	Interconnect Facility Finance Charge	13,656,799	Traditional OOR	13,656,799	3,842,260	9,814,539	0			0	0	8
10s	454	4204515	Operating Land & Facilities Rent Revenue	20,374,745	GRSM	0	0	0	20,374,745	P	4,250,081	16,124,663	0	2
10t	454	4867020	Nonoperating Misc Land & Facilities Rent		Traditional OOR	0	0	0	0			0	0	4
10u	454	-	Miscellaneous Adjustments		Traditional OOR	0	0	0	0			0	0	1
10v	454	4206515	Op Misc Land/Fac Rev	1,138,222	GRSM	0	0	0	1,138,222	P	603,066	535,156	0	2
10w	454	4184122	T-Unauth Pole Rent	(1,040)	Traditional OOR	(1,040)	0	(1,040)	0			0	0	4
10x	454	4184124	T-P&E Fees	54,750	Traditional OOR	54,750	0	54,750	0			0	0	4
10y	454	4184821	Rent Rev NU-NonBRRBA	76,611	Other Ratemaking	4,535	4,535	0	0			0	72,076	6, 12
10z	454	4184811	Fac Cost N/U-BRRBA	1,021,349	Other Ratemaking	60,454	60,454	0	0			0	960,895	6, 12
11	454 Total			78,053,707		53,676,621	4,010,660	49,665,961	21,700,415		4,901,447	16,798,968	2,676,671	
12	FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)			78,053,707										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	**FERC ACCT**	**ACCT**	**ACCT DESCRIPTION**	**DOLLARS**	**Category**	**Total**	**ISO**	**Non-ISO**	**Total**	**A/P**	**Threshold [10]**	**Incremental**	**Total**	**Notes**
12a	456	4186114	Energy Related Services	3,492,797	Traditional OOR	3,492,797	0	3,492,797	0			0	0	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	731,591	Traditional OOR	731,591	0	731,591	0			0	0	4
12c	456	4186120	Added Facilities - One Time Charge	219,628	Traditional OOR	219,628	0	219,628	0			0	0	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr		Traditional OOR	0	0	0	0			0	0	3
12e	456	4186126	Service Fee - Optimal Bill Prd	480	Traditional OOR	480	0	480	0			0	0	1
12f	456	4186128	Miscellaneous Revenues	520,007	Traditional OOR	520,007	0	520,007	0			0	0	1
12g	456	4186130	Tule Power Plant - Revenue		Traditional OOR	0	0	0	0			0	0	3
12h	456	4186142	Microwave Agreement	3,428	Traditional OOR	3,428	0	3,428	0			0	0	4
12i	456	4186150	Utility Subs Labor Markup		Traditional OOR	0	0	0	0			0	0	7
12j	456	4186155	Non Utility Subs Labor Markup	39,429	Other Ratemaking	2,334	2,334	0	0			0	37,096	6, 12
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	1,206	Traditional OOR	1,206	0	1,206	0			0	0	4
12l	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	12,102	Traditional OOR	12,102	0	12,102	0			0	0	4
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	3,657	Traditional OOR	3,657	0	3,657	0			0	0	4
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	828	Traditional OOR	828	0	828	0			0	0	4
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	704	Traditional OOR	704	0	704	0			0	0	4
12p	456	4186194	Property License Fee revenue	208,656	Traditional OOR	208,656	0	208,656	0			0	0	4
12q	456	4186512	Revenue From Recreation, Fish & Wildlife	1,683,569	GRSM	0	0	0	1,683,569	P	96,228	1,587,341	0	2
12r	456	4186514	Mapping Services	158,343	GRSM	0	0	0	158,343	P	25,615	132,728	0	2
12s	456	4186518	Enhanced Pump Test Revenue	31,125	GRSM	0	0	0	31,125	P	0	31,125	0	2
12t	456	4186524	Revenue From Scrap Paper - General Office		GRSM	0	0	0	0	P		0	0	2
12u	456	4186528	CTAC Revenues	2,800	GRSM	0	0	0	2,800	P	2,800	0	0	2
12v	456	4186530	AGTAC Revenues	5,365	GRSM	0	0	0	5,365	P	3,316	2,049	0	2
12w	456	4186716	ADT Vendor Service Revenue		GRSM	0	0	0	0	A		0	0	2
12xx	456	4186718	Read Water Meters - Irvine Ranch		GRSM	0	0	0	0	A		0	0	2
12yy	456	4186720	Read Water Meters - Rancho California		GRSM	0	0	0	0	A		0	0	2
12zz	456	4186722	Read Water Meters - Long Beach		GRSM	0	0	0	0	A		0	0	2
12aa	456	4186730	SSID Transformer Repair Services Revenue	24,950	GRSM	0	0	0	24,950	A		24,950	0	2
12bb	456	4186815	Employee Transfer/Affiliate Fee	296,571	Other Ratemaking	0	0	0	0			0	296,571	6
12cc	456	4186910	ITCC/CIAC Revenues	11,518,649	Traditional OOR	11,518,649	0	11,518,649	0			0	0	4
12dd	456	4186912	Revenue From Decommission Trust Fund	134,519,012	Other Ratemaking	0	0	0	0			0	134,519,012	6
12ee	456	4186914	Revenue From Decommissioning Trust FAS115	(35,894,910)	Other Ratemaking	0	0	0	0			0	(35,894,910)	6
12ff	456	4186916	Offset to Revenue from NDT Earnings/Realized	(134,518,430)	Other Ratemaking	0	0	0	0			0	(134,518,430)	6
12gg	456	4186918	Offset to Revenue from FAS 115 FMV	35,894,910	Other Ratemaking	0	0	0	0			0	35,894,910	6
12hh	456	4186920	Revenue From Decommissioning Trust FAS115-1	21,363,400	Other Ratemaking	0	0	0	0			0	21,363,400	6
12ii	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	(21,363,400)	Other Ratemaking	0	0	0	0			0	(21,363,400)	6
12jj	456	4188712	Power Supply Installations - IMS		GRSM	0	0	0	0	A		0	0	2
12kk	456	4188714	Consulting Fees - IMS		GRSM	0	0	0	0	A		0	0	2
12ll	456	4196105	DA Revenue	213,222	Traditional OOR	213,222	0	213,222	0			0	0	1
12mm	456	4196158	EDBL Customer Finance Added Facilities	4,153,401	Traditional OOR	4,153,401	0	4,153,401	0			0	0	4
12nn	456	4196162	SCE Energy Manager Fee Based Services	154,068	Traditional OOR	154,068	0	154,068	0			0	0	4
12oo	456	4196166	SCE Energy Manager Fee Based Services Adj		Traditional OOR	0	0	0	0			0	0	4
12pp	456	4196172	Off Grid Photo Voltaic Revenues		Traditional OOR	0	0	0	0			0	0	1
12qq	456	4196174	Scheduling/Dispatch Revenues		Traditional OOR	0	0	0	0			0	0	4
12rr	456	4196176	Interconnect Facilities Charges-Customer Financed	1,872,663	Traditional OOR	1,872,663	25,838	1,846,824	0			0	0	8
12ss	456	4196178	Interconnect Facilities Charges - SCE Financed	13,178,621	Traditional OOR	13,178,621	0	13,178,621	0			0	0	4
12tt	456	4196184	DMS Service Fees	2,537	Traditional OOR	2,537	0	2,537	0			0	0	4
12uu	456	4196188	CCA - Information Fees	673,778	Traditional OOR	673,778	0	673,778	0			0	0	6
12vv	456	-	Miscellaneous Adjustments		Traditional OOR	0	0	0	0			0	0	1
12ww	456	4186911	Grant Amortization	3,333,000	Other Ratemaking	0	0	0	0			0	3,333,000	6
12xx	456	4186925	GHG Allowance Revenue	376,175,077	Other Ratemaking	0	0	0	0			0	376,175,077	6
12yy	456	4186132	Intercon One Time	1,391,189	Traditional OOR	1,391,189	0	1,391,189	0			0	0	4
12zz	456	4186116	EV Charging Revenue	502	Traditional OOR	502	0	502	0			0	0	4
12aaa	456	4186115	Energy Reltd Srv-TSP	694,292	Traditional OOR	694,292	0	694,292	0			0	0	4
12bbb	456	4186156	N/U Labor Mrkp-BRRBA	155,623	Other Ratemaking	9,211	9,211	0	0			0	146,411	6, 12
12ccc	456	4188720	LCFS CR 411.8	15,016,500	Traditional OOR	15,016,500	0	15,016,500	0			0	0	4
12ddd	456	4186128	Miscellaneous Revenues - ISO	18,000,000	Traditional OOR	18,000,000	18,000,000	0	0			0	0	5
13	**456 Total**			**453,970,935**		**72,076,047**	**18,037,384**	**54,038,664**	**1,906,151**		**127,958**	**1,778,193**	**379,988,737**	
14	**FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)**			**453,970,935**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
							Traditional OOR				GRSM		Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
15a	456.1	4188112	Trans of Elec of Others - Pasadena		Traditional OOR	0	0	0	0			0	0	5
15b	456.1	4188114	FTS PPU/Non-ISO	296,028	Traditional OOR	296,028	0	296,028	0			0	0	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	992,563	Traditional OOR	992,563	0	992,563	0			0	0	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	3,430,468	Other Ratemaking	0	0	0	0			0	3,430,468	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	51,529,376	Other Ratemaking	0	0	0	0			0	51,529,376	6
15f	456.1	4188816	ISO-Congestion Revenue	15,738,131	Other Ratemaking	0	0	0	0			0	15,738,131	6
15g	456.1	4198110	Transmission of Elec of Others	46,734,870	Traditional OOR	46,734,870	46,734,870	0	0			0	0	5
15h	456.1	4198112	WDAT	5,539,948	Traditional OOR	5,539,948	0	5,539,948	0			0	0	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	394,622	Traditional OOR	394,622	0	394,622	0			0	0	4
15j	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	1,080,948	Traditional OOR	1,080,948	0	1,080,948	0			0	0	4
15k	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	402,148	Traditional OOR	402,148	0	402,148	0			0	0	4
15l	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	209,706	Traditional OOR	209,706	0	209,706	0			0	0	4
15m	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	551,002	Traditional OOR	551,002	0	551,002	0			0	0	4
15n	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	651,331	Traditional OOR	651,331	0	651,331	0			0	0	4
15o	456.1	4198126	High Desert Tie-Line Rental Rev	264,133	Traditional OOR	264,133	0	264,133	0			0	0	4
15p	456.1	4198130	Inland Empire CRT Tie-Line EX	42,492	Traditional OOR	42,492	0	42,492	0			0	0	4
15q	456.1	4198910	Reliability Service Revenue - Non-PTO's	146,964	Other Ratemaking	0	0	0	0			0	146,964	6
15r	456.1	4198132	Radial Line Agreement-Base-Mojave Solr	90,533	Traditional OOR	90,533	0	90,533	0			0	0	4
15s	456.1	4198134	Radial Line Agreement-O&M-Mojave Solr	229,854	Traditional OOR	229,854	0	229,854	0			0	0	4
15t	456.1	4188716	ISO Non-Refundable Interconnection Deposit	2,295,276	Other Ratemaking	0	0	0	0			0	2,295,276	6
16	**456.1 Total**			**130,620,392**		**57,480,178**	**46,734,870**	**10,745,308**	**0**		**0**	**0**	**73,140,214**	
17	**FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)**			**130,620,392**										
18a														
19	**457.1 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
20	**FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)**			**0**										
21a														
22	**457.2 Total**			**0**		**0**	**0**	**0**	**0**		**0**	**0**	**0**	
23	**FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)**			**0**										
	Edison Carrier Solutions (ECS)													
24a	417	4863130	ECS - Distribution Facilities	574,600	GRSM	0	0	0	574,600	P	144,854	429,745	0	2
24b	417	4862110	ECS - Dark Fiber	6,212,981	GRSM	0	0	0	6,212,981	A	1,279,826	4,933,155	0	2
24c	417	4862115	ECS - SCE Net Fiber	3,296,985	GRSM	0	0	0	3,296,985	A	680,429	2,616,556	0	2
24d	417	4862120	ECS - Transmission Right of Way	283,552	GRSM	0	0	0	283,552	A	57,963	225,589	0	2
24e	417	4862135	ECS - Wholesale FCC	22,638,372	GRSM	0	0	0	22,638,372	A	4,775,918	17,862,453	0	2
24f	417	4864115	ECS - EU FCC Rev	745,271	GRSM	0	0	0	745,271	A	71,150	674,122	0	2
24g	417	4862125	ECS - Cell Site Rent and Use (Active)	12,189,272	GRSM	0	0	0	12,189,272	A	1,853,751	10,335,521	0	2
24h	417	4862130	ECS - Cell Site Reimbursable (Active)	6,089,441	GRSM	0	0	0	6,089,441	A	1,577,178	4,512,264	0	2
24i	417	4863120	ECS - Communication Sites	347,613	GRSM	0	0	0	347,613	P	71,332	276,282	0	2
24j	417	4863110	ECS - Cell Site Rent and Use (Passive)	3,391,715	GRSM	0	0	0	3,391,715	P	643,245	2,748,471	0	2
24k	417	4863115	ECS - Cell Site Reimbursable (Passive)	415,112	GRSM	0	0	0	415,112	P	28,024	387,088	0	2
24l	417	4863125	ECS - Micro Cell	1,794,379	GRSM	0	0	0	1,794,379	P	456,813	1,337,566	0	2
24m	417	4864120	ECS - End User Universal Service Fund Fee	100,891	GRSM	0	0	0	100,891	A	1,488	99,403	0	2
24n	417	4864116	ECS - Instrastate End User Revenue	78,015	GRSM	0	0	0	78,015	A	0	78,015	0	2
24o	417	4864121	ECS - Intrastate End User Fees	669	GRSM	0	0	0	669	A	0	669	0	2
25	**417 ECS Total**			**58,158,870**		**0**	**0**	**0**	**58,158,870**		**11,641,969**	**46,516,900**	**0**	
26	**417 Other**			**7,775,931**										
27	**FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)**			**65,934,801**										

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
						Traditional OOR			GRSM				Other Ratemaking	
Line	FERC ACCT	ACCT	ACCT DESCRIPTION	DOLLARS	Category	Total	ISO	Non-ISO	Total	A/P	Threshold [10]	Incremental	Total	Notes
	Subsidiaries													
28a	418.1		ESI (Gross Revenues - Active)		GRSM	0	0	0	0	A		0	0	2,9
28b	418.1		ESI (Gross Revenues - Passive)		GRSM	0	0	0	0	P		0	0	2,9
28c	418.1		Southern States Realty	14,200	GRSM	0	0	0	14,200	P		14,200	0	2, 15
28d	418.1		Mono Power Company	9,165	Traditional OOR	9,165	0	9,165	0			0	0	13
28e	418.1		Edison Material Supply (EMS)	958,989	Traditional OOR	958,989	56,763	902,227	0			0	0	7, 17
29	**418.1 Subsidiaries Total**			**982,354**		**968,154**	**56,763**	**911,392**	**14,200**		**0**	**14,200**	**0**	
30	**418.1 Other (See Note 16)**			**(958,989)**										
31	**FF-1 Total for Account 418.1 -Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)**			**23,365**										
32			**Totals**	**873,049,796**		**334,552,188**	**68,839,676**	**265,712,512**	**81,779,697**		**16,671,389**	**65,108,308**	**456,717,910**	

Line		Description	Amount	Calculation
33		Ratepayers' Share of Threshold Revenue	16,671,389	= Line 32K
34		ISO Ratepayers' Share of Threshold Revenue	5,425,127	Note 11
35				
36		Total Active Incremental Revenue	41,362,698	= Sum Active categories in column L
37		Ratepayers' Share of Active Incremental Revenue	4,136,270	= Line 36D * 10%
38		Total Passive Incremental Revenue	23,745,609	= Sum Passive categories in column L
39		Ratepayers' Share of Passive Incremental Revenue	7,123,683	= Line 38D * 30%
40		Total Ratepayers' Share of Incremental Revenue	11,259,953	= Line 37D + Line 39D
41		ISO Ratepayers' Share of Incremental Revenue (%)	32.54%	see Note 11
42		ISO Ratepayers' Share of Incremental Revenue	3,664,162	= Line 40D * Line 41D
43		**Tot. ISO Ratepayers' Share NTP&S Gross Rev.**	**9,089,289**	= Line 34D + Line 42D

Line		Amount	Calculation
44	**Total Revenue Credits:**	$77,928,965	Sum of Column D, Line 43 and Column G, Line 32

Notes:

1- CPUC Jurisdictional service related.

2- Subject to sharing per the Gross Revenue Sharing Mechanism (GRSM), adopted in CPUC D.99-09-070. On an annual basis, once SCE obtains $16,671,389.55 (Threshold Revenue) in NTP&S Revenues, any additional revenues (Incremental Gross Revenues) that SCE receives are shared between shareholders and ratepayers. For GRSM categories deemed Active, the Incremental Gross Revenues are shared 90/10 between shareholders and ratepayers. For those categories deemed Passive, the Incremental Gross Revenues are shared 70/30 between shareholders and ratepayers.

3- Generation related.

4- Non-ISO facilities related.

5- ISO transmission system related.

6- Subject to balancing account treatment

7- Allocated based on CPUC GRC allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year.
ISO Allocator = 0.05919 Source: CPUC D. 15-11-021

8- ISO portion of Traditional OOR relates to monthly revenues received from customers for facilities that are part of the ISO network.

9- Edison ESI is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for ESI are reported on Acct 418.1, pg 225.5e.

10- The first $16,671,389 million in gross revenues generated by GRSM activities are automatically classified as Threshold Revenue.

11- Allocator is equal to the jurisdictional split of the Threshold Revenue, which is jurisdictionalized as $5.425M to FERC ratepayers and $11.246M to CPUC ratepayers per the 2009 CPUC General Rate Case (D. 09-03-025). The ISO ratepayers' share of ratepayer revenue is $5.425M/$16.671M = 32.54%.

12- Allocated based on the CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator in effect during the Prior Year. The weighted average (by time) shall be used if more than one allocator is in effect during the Prior Year. ISO portion of revenue is treated as traditional OOR.
ISO Allocator = 0.05919 Source: CPUC D. 15-11-021

13- Mono Power Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.11e. Revenues and costs shall be non-ISO.

14- SCE Capital Company is a subsidiary company. Net Earnings are reported on Acct 418.1, pg 225.23e. Revenues and costs shall be non-ISO.

15- Southern States Realty is a subsidiary company. Gross revenues are not reported in FF-1, only net earnings. Net Earnings for Southern States Realty are reported on Acct 418.1, pg 225.17e.

16- For subsidiaries that are subject to GRSM, Column D contains gross revenues. Input on Line 30D contains the associated expenses.

17- Per GRC Decision D.87-12-066, for ratemaking purposes EMS financials are consolidated with SCE's. See FERC Form 1 page 123.3 under "Equity Investment Differences" . Consequently, net income of EMS is not reported separately in FERC Form 1 and is not a part of FERC Account 418.1 totals. To ensure that ratepayers receive the net income from this subsidiary SCE includes EMS net income in the formula on line 28f. This amount is reversed as part of line 30 to remain consistent with the totals reported in FERC Form 1.

NETWORK UPGRADE CREDIT AND INTEREST EXPENSE

Prior Year:

1) Beginning of Year Balances: (Note 1)

Line		Balance	Notes
1	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$27,134,526	See Note 1
2	Acct 252 Other	$201,105,450	Line 3 - Line 1
3	Total Acct 252 - Customer Advances for Construction	$228,239,976	FF1 113.56d
	2) End of Year Balances: (Note 2)		
4	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$119,779,556	See Note 3
5	Acct 252 Other	$91,604,742	Line 6 - Line 4
6	Total Acct 252 - Customer Advances for Construction	$211,384,298	FF1 113.56c
7	Average Outstanding Network Upgrade Credits Beginning and End of Year	$73,457,041	(Line 1 + Line 4) / 2
8	Interest On Network Upgrade Credits Recorded in FERC Acct 242	$2,616,283	See Note 4
9	Acct 242 Other	$512,307,469	Line 10 - Line 8
10	Total Acct 242 - Miscellaneous Current and Accrued Liabilities	$514,923,752	FF1 113.48c

Notes:

1. Beginning of Year Balances are from December of the year previous to the Prior Year.
2. End of Year Balances are from December of the Prior Year.
3. Only projects that are in Rate Base in the year reported are included.
4. Interest relates to refund of facility and one-time payments by generator. For facility costs, pre-in-service date interest is excluded. For one-time costs, pre-in-service and post-in-service interest is included.

Determination of Regulatory Assets/Liabilities and Associated Amortization and Regulatory Debits/Credits

Line		Prior Year Amount	Calculation or Source
1	Other Regulatory Assets/Liabilities are a component of Rate Base representing costs that are created resulting from the ratemaking		
2	actions of regulatory agencies. Pursuant to the Commission's Uniform System of Accounts, these items include amounts recorded		
3	in accounts 182.x and 254. This Schedule shall not include any costs recovered through Schedule 12.		
4			
5	SCE shall include a non-zero amount of Other Regulatory Assets/Liabilities only with Commission		
6	approval received subsequent to an SCE Section 205 filing requesting such treatment.		
7			
8	Amortization and Regulatory Debits/Credits are amounts approved for recovery in this formula transmission rate representing the		
9	approved annual recovery of Other Regulatory Assets/Liabilities as an expense item in the Base TRR, consistent		
10	with a Commission Order.		
11			
12		Prior Year	
13		Amount	Calculation or Source
14	Other Regulatory Assets/Liabilities (EOY):	$0	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	$0	Avg. of Sum of Cols. 1 and 2 below
16	Amortization and Regulatory Debits/Credits:	$0	Sum of Column 3 below

Line	Description of Issue Resulting in Other Regulatory Asset/Liability	Col 1 Prior Year BOY Other Reg Asset/Liability	Col 2 Prior Year EOY Other Reg Asset/Liability	Col 3 Prior Year Amortization or Regulatory Debit/Credit	Commission Order Granting Approval of Regulatory Liability
17	Issue #1				
18	Issue #2				
19	Issue #3				
20	Totals:	$0	$0	$0	Sum of above

Instructions:

1) Upon Commission approval of recovery of Other Regulatory Assets/Liabilities, Amortization and Regulatory Debits/Credits costs through this formula transmission rate:
   a) Fill in Description for issue in above table.
   b) Enter costs in columns 1-3 in above table for the applicable Prior Year.
2) Add additional lines as necessary for additional issues.

Calculation of the Contribution of CWIP to the Base TRR

1) CWIP Contribution to the Prior Year TRR and True Up TRR

a) CWIP Balances:

Line	Project	Col 1 Prior Year EOY Amount	Col 2 Prior Year Average Amount	Col 3 Forecast Period Amount	Source
1	Tehachapi:	$14,915,548	$194,883,792	-$14,915,548	10-CWIP, Lines 13, 14, 80
2	Devers to Colorado River:	$0	$0	$0	10-CWIP, Lines 13, 14, 106
3	South of Kramer:	$4,204,927	$3,394,860	$1,836,037	10-CWIP, Lines 13, 14, 132
4	West of Devers:	$69,685,245	$56,339,988	$155,484,662	10-CWIP, Lines 13, 14, 158
5	Red Bluff:	$0	$709,238	$0	10-CWIP, Lines 13, 14, 184
6	Whirlwind Sub Expansion:	$26,943,987	$16,606,020	-$26,943,987	10-CWIP, Lines 27, 28, 210
7	Colorado River Sub Expansion:	$0	$0	$0	10-CWIP, Lines 27, 28, 236
8		$0	$0	$0	10-CWIP, Lines 27, 28, 262
9		$0	$0	$0	10-CWIP, Lines 27, 28, 288
10		$0	---	$0	10-CWIP, Lines 27, 28, 314
11		$0	---	$0	10-CWIP, Lines 27, 28, 340
12	Totals:	$115,749,706	$271,933,898	$115,461,165	Sum of Lines 1 to 11

b) Return:

Line		EOY Amount	Average Amount	Source
13	CWIP Amount:	$115,749,706	$271,933,898	Line 12
14	Cost of Capital Rate:	7.9920%	7.9920%	1-BaseTRR, Line 54
15	Cost of Capital:	$9,250,755	$21,733,048	Line 13 * Line 14

c) Income Taxes

Line		EOY Amount	Average Amount	Source
16	CWIP Amount:	$115,749,706	$271,933,898	Line 12
17	Equity ROR w Preferred Stock ("ER"):	5.9926%	5.9926%	1-BaseTRR, Line 55
18	Composite Tax Rate:	40.7460%	40.7460%	1-BaseTRR, Line 59
19	Income Taxes:	$4,769,861	$11,205,964	Formula on Line 21

20

21 Income Taxes = [(RB * ER) * (CTR/(1 – CTR)], or [(L13 * L17) * (L18 / (1 - L18)]

22 (No "Credits and Other" or "AFUDC" Terms, since these are not related to CWIP)

23

d) ROE Incentives:

Line		Value	Source
24	IREF =	$8,538	15-IncentiveAdder, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	
25	Tehachapi CWIP Amount:	$14,915,548	$194,883,792	Line 1
26	ROE Adder %:	1.25%	1.25%	15-IncentiveAdder, Line 5
27	ROE Adder $:	$159,193	$2,079,981	Formula on Line 32

2) Devers to Colorado River

Line		EOY Amount	Average Amount	
28	DCR CWIP Amount:	$0	$0	Line 2
29	ROE Adder %:	1.00%	1.00%	15-IncentiveAdder, Line 6
30	ROE Adder $:	$0	$0	Formula on Line 32

31

32 ROE Adder $ = (Project CWIP Amount/$1,000,000) * IREF * (ROE Adder % / 1%)

e) Total of Return, Income Taxes, and ROE Incentives contribution to PYTRR and True Up TRR

Line		PYTRR Amount	True Up TRR Amount	Source
33	Return:	$9,250,755	$21,733,048	Line 15
34	Income Taxes:	$4,769,861	$11,205,964	Line 19
35	ROE Adder Tehachapi:	$159,193	$2,079,981	Line 27
36	ROE Adder DCR:	$0	$0	Line 30
37	FF&U:	$164,674	$322,374	Note 1
38	Total:	$14,344,484	$35,341,367	Sum Lines 33 to 37

f) Contribution from each Project to the Prior Year TRR and True Up TRR

1) Contribution to the Prior Year TRR

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF&U	Col 5 = Sum C1 to C4 Total	Source
39	Tehachapi:	$1,192,056	$614,646	$159,193	$22,831	$1,988,725	Note 2
40	Devers to Colorado River:	$0	$0	$0	$0	$0	Note 2
41	South of Kramer:	$336,059	$173,278	$0	$5,915	$515,253	Note 2
42	West of Devers:	$5,569,268	$2,871,618	$0	$98,027	$8,538,913	Note 2
43	Red Bluff:	$0	$0	$0	$0	$0	Note 2
44	Whirlwind Sub Expansion:	$2,153,372	$1,110,319	$0	$37,902	$3,301,594	Note 2
45	Colorado River Sub Expansion:	$0	$0	$0	$0	$0	Note 2
46		$0	$0	$0	$0	$0	Note 2
47		$0	$0	$0	$0	$0	Note 2
48		---	---	---	---	---	Note 2
49		---	---	---	---	---	Note 2
50	Totals:	$9,250,755	$4,769,861	$159,193	$164,674	$14,344,484	Sum L 39 to L 49

2) Contribution to the True Up TRR

	Project	Col 1 Cost of Capital	Col 2 Income Taxes	Col 3 ROE Adder	Col 4 FF&U	Col 5 = Sum C1 to C4 Total	Source
51	Tehachapi:	$15,575,178	$8,030,851	$2,079,981	$298,299	$25,984,310	Note 3
52	Devers to Colorado River:	$0	$0	$0	$0	$0	Note 3
53	South of Kramer:	$271,318	$139,897	$0	$4,776	$415,991	Note 3
54	West of Devers:	$4,502,711	$2,321,681	$0	$79,254	$6,903,646	Note 3
55	Red Bluff:	$56,683	$29,227	$0	$998	$86,907	Note 3
56	Whirlwind Sub Expansion:	$1,327,159	$684,308	$0	$23,360	$2,034,826	Note 3
57	Colorado River Sub Expansion:	$0	$0	$0	$0	$0	Note 3
58		$0	$0	$0	$0	$0	Note 3
59		$0	$0	$0	$0	$0	Note 3
60		---	---	---	---	---	Note 3
61		---	---	---	---	---	Note 3
62	Totals:	$21,733,048	$11,205,964	$2,079,981	$406,686	$35,425,679	Sum of L 51 to 61

2) Contribution from the Incremental Forecast Period TRR

a) Total of all CWIP projects

		Value	Source
63	Forecast Period Incremental CWIP:	$115,461,165	Line 12, Col 3
64	AFCRCWIP:	12.113%	2-IFPTRR, Line 16
65	CWIP component of IFPTRR without FF&U:	$13,985,666	Line 63 * Line 64
66	FF&U:	$162,420	Line 65 * (28-FFU, L5 FF Factor + U Factor)
67	CWIP component of IFPTRR including FF&U:	$14,148,086	Line 65 + Line 66

b) Individual Project Contribution

	Project	Amount wo FF&U	Amount with FF&U	Source
68	Tehachapi:	-$1,806,702	-$1,827,683	Note 4
69	Devers to Colorado River:	$0	$0	Note 4
70	South of Kramer:	$222,397	$224,980	Note 4
71	West of Devers:	$18,833,662	$19,052,383	Note 4
72	Red Bluff:	$0	$0	Note 4
73	Whirlwind Sub Expansion:	-$3,263,691	-$3,301,594	Note 4
74	Colorado River Sub Expansion:	$0	$0	Note 4
75		$0	$0	Note 4
76		$0	$0	Note 4
77		---	---	Note 4
78		---	---	Note 4
79	Totals:	$13,985,666	$14,148,086	Sum of Lines 68 to 78

3) Total Contribution of CWIP to the Retail and Wholesale Base TRRs:

a) Total of all CWIP projects

		Value	Source
80	PY Total Return, Taxes, Incentive:	$14,179,809	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	$13,985,666	Line 65
82	Total without FF&U:	$28,165,475	Line 80 + Line 81
83	FF Factor:	0.9206%	28-FFU, Line 5
84	U Factor:	0.2408%	28-FFU, Line 5
85	Franchise Fees Amount:	$259,283	Line 82 * Line 83
86	Uncollectibles Amount:	$67,811	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	$28,492,569	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	$28,424,758	Line 82 + Line 85

b) Individual CWIP Project Contribution to the Retail Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF&U	Col 4 Total	Source
89	Tehachapi:	$1,965,894	-$1,806,702	$1,849	$161,041	Note 5
90	Devers to Colorado River:	$0	$0	$0	$0	Note 5
91	South of Kramer:	$509,338	$222,397	$8,498	$740,232	Note 5
92	West of Devers:	$8,440,886	$18,833,662	$316,748	$27,591,296	Note 5
93	Red Bluff:	$0	$0	$0	$0	Note 5
94	Whirlwind Sub Expansion:	$3,263,691	-$3,263,691	$0	$0	Note 5
95	Colorado River Sub Expansion:	$0	$0	$0	$0	Note 5
96		$0	$0	$0	$0	Note 5
97		$0	$0	$0	$0	Note 5
98		---	---	---	---	Note 5
99		---	---	---	---	Note 5
100	Totals:	$14,179,809	$13,985,666	$327,094	$28,492,569	

c) Individual CWIP Project Contribution to the Wholesale Base TRR

		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF	Col 4 Total	Source
101	Tehachapi:	$1,965,894	-$1,806,702	$1,465	$160,658	Note 6
102	Devers to Colorado River:	$0	$0	$0	$0	Note 6
103	South of Kramer:	$509,338	$222,397	$6,736	$738,471	Note 6
104	West of Devers:	$8,440,886	$18,833,662	$251,081	$27,525,629	Note 6
105	Red Bluff:	$0	$0	$0	$0	Note 6
106	Whirlwind Sub Expansion:	$3,263,691	-$3,263,691	$0	$0	Note 6
107	Colorado River Sub Expansion:	$0	$0	$0	$0	Note 6
108		$0	$0	$0	$0	Note 6
109		$0	$0	$0	$0	Note 6
110		---	---	---	---	Note 6
111		---	---	---	---	Note 6
112	Totals:	$14,179,809	$13,985,666	$259,283	$28,424,758	

Notes:

1) (Sum Lines 33 to 36) * (FF + U Factors from 28-FFU) for Prior Year TRR
(Sum Lines 34 to 37) * (FF Factor from 28-FFU) for True Up TRR
2) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 1.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on 28-FFU.
3) Project Cost of capital is a fraction of total Cost of Capital on Line 15 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
Project Income Taxes is a fraction of total Income on Line 19 based on fraction of project CWIP Balances on Lines 1 to 12, Col 2.
ROE Adder is from Lines 35 and 36. FF&U Expenses are based on FF&U Factors on 28-FFU.
4) Project contribution to total IFPTRR is based on fraction of Forecast Period CWIP Balances on Lines 1 to 12, Col 3.
5) Column 1 is from Lines 39 to 49, Sum of Column 1-3 (no FF&U).
Column 2 is from Lines 68 to 78 (no FF&U).
Column 3 is the product of (C1 + C2) and the sum of FF and U factors (28-FFU, L5)
6) Same as Note 5 except no Uncollectibles Expense in Column 3.

Calculation of Wholesale Difference to the Base TRR

Inputs are shaded yellow

The Wholesale Difference to the Base TRR represents the amount by which the Wholesale Base TRR differs as compared to the Retail Base TRR. This difference is attributable to differences in the following six items, as approved by Commission Order 86 FERC ¶ 63,014 in Docket No. ER97-2355.

These six items may affect the Base TRR by affecting Rate Base, or affecting an annual expense (amortization). If the annual amortization affects Income Taxes, there is an additional annual Income Tax Effect. The table summarizes these impacts for each item:

Line		Rate Base Difference	Expense (Amortization) Difference	Expense Tax Impact
1	a) Depreciation	Yes	Yes	No
2	b) Taxes Deferred -Make Up Adjustment (South Georgia)	Yes	Yes	Yes
3	c) Excess Deferred Taxes	Yes	Yes	Yes
4	d) Taxes Deferred - Acct. 282 ACRS/MACRS	Yes	Yes	No
5	e) Uncollectibles Expense	No	Yes	No
6	f) EPRI and EEI Dues	No	Yes	No

1) Calculation of Wholesale Rate Base Difference and Wholesale Rate Base Adjustment

a) Quantification of the Initial 2010 Wholesale Rate Base Difference and annual change
The difference between Retail and Wholesale Rate Base is attributable to the following four items, with the Initial Prior Year 2010 Rate Base differences and annual changes as follows:

		Data Source		Col 1 2010 Rate Base Difference (Wholesale less Retail)	Col 2 Annual Change (Amortization)
7	1) Accumulated Depreciation	Fixed values		$31,556,000	-$2,176,300
8	2) Taxes Deferred - Make Up Adjustment	Fixed values		-$35,044,000	$2,503,000
9	3) Excess Deferred Taxes	Fixed values		-$624,650	$43,100
10	4) Taxes Deferred - Acct. 282 ACRS/MACRS	Fixed values		-$7,410,000	$511,200
11			Totals:	-$11,522,650	$881,000

b) Quantification of the Wholesale Rate Base Adjustment
The Wholesale Rate Base Adjustment represents the impact on the Wholesale Base TRR relative to the Retail Base TRR of the Wholesale Rate Base Difference for the Prior Year.

		Data Source	Value	Notes/Instructions
12	Fixed Charge Rate	2-IFPTRR Line 16	12.11%	1
13	Prior Year		2016	2
14	Wholesale Rate Base Difference for Prior Year		-$6,236,650	3
15	Wholesale Rate Base Adjustment	Line 14 * Line 12	-$755,438	

2) Calculation of Wholesale Expense Difference

The annual Wholesale Expense Difference impact is the negative of amounts stated in Lines 7 to 10 above, Column 2. It represents the effect on expenses (Wholesale less Retail) of amortizing the associated balances each year. If an annual amortization amount affects Income Taxes, the expense difference must be grossed up for income taxes.

a) Calculation of the Wholesale South Georgia Income Tax Adjustment to the TRR

		Source	Value
16	South Georgia Amortization	Line 8	$2,503,000
17	Composite Tax Rate ("CTR")	1-BaseTRR L 59	40.746%
18	Tax Gross Up Factor	(1/(1-CTR))	1.6876
19	Wholesale South Georgia		
20	Income Tax Adjustment to the TRR:	- Line 16 * Line 18	-$4,224,187

b) Calculation of "Excess Deferred Taxes" Grossed Up for Income Taxes

		Source	Value
21	Annual Amort. of "Excess Deferred Taxes":	Line 9	$43,100
22	Tax Gross Up Factor	Line 18	1.6876
23	Excess Deferred Taxes Grossed Up for Income Taxes:	- Line 21 * Line 22	-$72,738
24			

25	**c) Calculation of EPRI and EEI Dues Exclusion**			
26		**Source**		**Notes/Instructions**
27	EPRI Dues	SCE Records	$0	Note 5
28	EEI Dues	SCE Records	$1,604,261	Note 5
29	Sum of EPRI and EEI Dues	Line 27 + 28	$1,604,261	
30	Transmission Wages and Salaries Allocation Factor	27-Allocators, Line 9	6.1650%	
31	EPRI and EEI Dues Exclusion	Line 29 * 30	$98,903	
	d) Total Expense Difference			**Notes/Instructions**
32	1) Wholesale Depreciation Difference	- Line 7, Col. 2	$2,176,300	
33	2) Taxes Deferred - Make Up Adjustment	Line 20	-$4,224,187	
34	3) Excess Deferred Taxes	Line 23	-$72,738	
35	4) Taxes Deferred - Acct. 282 ACRS/MACRS	- Line 10, Col. 2	-$511,200	
36	5) EPRI and EEI Dues Exclusion	- Line 31	-$98,903	
37	6) Additional Expense Difference		$0	Note 6
38		Total Expense Difference:	-$2,730,728	

3) Calculation of the Wholesale Difference to the Base TRR

		Source	Value	
39	Wholesale Rate Base Adjustment	Line 15	-$755,438	
40	Expense Difference	Line 38	-$2,730,728	
41	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 80	-$2,617,003	
42	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	-$260,189	
43	Subtotal:	Sum Line 39 to Line 42	-$6,363,357	
44	Franchise Fee Exclusion		-$32,093	Note 4
45	Wholesale Difference to the Base TRR:	Line 43 + Line 44	-$6,395,449	

Notes/Instructions:

1) Fixed Charge Rate of capital and income tax costs associated with $1 of Rate Base is defined elsewhere in this formula as "AFCRCWIP".
2) Input Prior Year for this Informational Filing in Line 13.
3) Calculation: (Line 11, Col 1) + ((Line 11, Col 2) * (Line 13 - 2010)).
4) Franchise Fee Exclusion is equal to the Franchise Fee Factor on the 28-FFU Line 5 times Line 39 + 40.
5) Only exclude if not already excluded in Schedule 20.

Income Tax Rates

Line		Prior Year	Federal Income Tax Rate ("FITR")		Source
	1) Federal Income Tax rate			Inputs are shaded yellow	
1		2016	35.00%	Note 1	
2					
3	**2) Composite State Income Tax Rate**				
4					
5			**Composite State**		
6		**Prior**	**Income Tax**		
7		**Year**	**Rate ("CSITR")**		**Source**
8		2016	8.8400%	Note 2	
9					
10					
11					

Line	Description	Amount
12	**3) Capitalized Overhead portion of Electric Payroll Tax Expense**	
13		**Amount**
14	Total Electric Payroll Tax Expense (From 1-BaseTRR, Line 31)	$116,164,312
15	Capitalization Rate (Note 3)	39.8%
16	Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 * Line 15)	$46,233,396
17	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 - Line 16)	$69,930,916

Notes:
1) Federal Source Statute: Internal Revenue Code Section 11(b)(1)(D)
2) California State Source Statue:
California Rev. & Tax. Cd. § 23151
3) Capitalization Rate approved in: CPUC D. 15-11-021
For the following Prior Years: 2015-2017

Calculation of Allocation Factors

Inputs are shaded yellow

1) Calculation of Transmission Wages and Salaries Allocation Factor

Line		Notes	FERC Form 1 Reference or Instruction	Prior Year Value
1	ISO Transmission Wages and Salaries		19-OandM Line 91, Col. 7	$35,781,164
2	Total Wages and Salaries		FF1 354.28b	$737,797,550
3	Less Total A&G Wages and Salaries		FF1 354.27b	$205,867,991
4	Total Wages and Salaries wo A&G		Line 2 - Line 3	$531,929,559
5	Total NOIC (Non-Officer Incentive Compensation)		20-AandG, Note 2	$71,991,890
6	Less A&G NOIC		20-AandG, Note 2	$23,529,616
7	NOIC wo A&G NOIC		Line 5 - Line 6	$48,462,274
8	Total non-A&G W&S with NOIC		Line 4 + Line 7	$580,391,833
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	6.1650%
10				
11	**2) Calculation of Transmission Plant Allocation Factor**			
12			**FERC Form 1 Reference**	**Prior Year**
13		**Notes**	**or Instruction**	**Value**
14	Transmission Plant - ISO		7-PlantStudy, Line 21	$8,276,570,295
15	Distribution Plant - ISO		7-PlantStudy, Line 30	$0
16	Total Electric Miscellaneous Intangible Plant		6-PlantInService, Line 21, C2	$1,588,136,353
17	Electric Miscellaneous Intangible Plant - ISO		Line 16 * Line 9	$97,908,627
18	Total General Plant		6-PlantInService, Line 21, C1	$2,941,903,413
19	General Plant - ISO		Line 18 * Line 9	$181,368,384
20	Total Plant In Service		FF1 207.104g	$44,298,088,225
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	19.3143%
23				
24	**3) Schedule 19 "Percent ISO" Allocation Factors (Input values are from SCE Records)**			
25				

Line		Values	Notes	Applied to Accounts
26	a) Line Miles	**Values**	**Notes**	**Applied to Accounts**
27	ISO Line Miles	5,660		563 --Overhead Line Expenses - Allocated
28	Non-ISO Line Miles	6,453		567 - Line Rents - Allocated
29	Total Line Miles	12,113	= L27 + L28	571 - Maintenance of Overhead Lines - Allocated
30	Line Miles Percent ISO	46.7%	= L27 / L29	
31				
32	b) Underground Line Miles	**Values**	**Notes**	**Applied to Accounts**
33	ISO Underground Line Miles	5		564 - Underground Line Expense
34	Non-ISO Underground Line Miles	353		572 - Maintenance of Underground Transmission Lines
35	Total Undergound Line Miles	358	= L33 + L34	
36	Underground Line Miles Percent ISO	1.4%	= L33 / L35	
37				
38	c) Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
39	ISO Circuit Breakers	1,184		All Other Non 0% or 100% Transmission O&M Accounts
40	Non-ISO Breakers	2,078		
41	Total Circuit Breakers	3,262	= L39 + L40	
42	Circuit Breakers Percent ISO	36.3%	= L39 / L41	
43				
44	d) Distribution Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
45	ISO Distribution Circuit Breakers	0		582 - Station Expenses
46	Non-ISO Distribution Circuit Breakers	8,875		590 - Maintenance Supervision and Engineering
47	Total Distribution Circuit Breakers	8,875	= L45 + L46	591 - Maintenance of Structures
48	Distribution Circuit Breakers Percent ISO	0.0%	= L45 / L47	592 - Maintenance of Station Equipment

Franchise Fees and Uncollectibles Expense Factors

1) Approved Franchise Fee Factor(s)

Inputs are shaded yellow

Line	From	To	Days in Prior Year	FF Factor	Reference
1	2016	Present	366	0.92057%	Schedule 28 - Workpaper, Line 3
2					

2) Approved Uncollectibles Expense Factor(s)

	From	To	Days in Prior Year	U Factor	Reference
3	2016	Present	366	0.24076%	Schedule 28 - Workpaper, Line 4
4					

3) FF and U Factors

	Prior Year	FF Factor	U Factor	Notes
5	2016	0.92057%	0.24076%	Calculated according to Instruction 3

Notes:
1) Franchise Fees represent payments that SCE makes to municipal entities for the right to locate facilities within the municipality.

Instructions:
1) Enter Franchise Fee and Uncollectibles Factors as approved by the California Public Utilities Commission ("CPUC") in modules 1 and 2 above pursuant to Instruction 2. If approved factors changed during Prior Year, enter both, and note period of time for which each applies in "From" and "To" columns, and number of days each was in effect during the Prior Year in "Days in Prior Year" Column.
2) Franchise Fees Factor is calculated from CPUC Decision by dividing adopted Franchise Fees by Total Operating Revenues less Franchise Fees. Uncollectibles Factor is calculated by dividing adopted Uncollectibles expense by Total Operating revenues less Uncollectibles Expense. Resulting FF & U Factors represent factors that, when applied to TRR without FF and U will correctly determine FF and U expense.
3) Calculate in module 3 the weighted average FF and U factors from the factors in modules 1 and 2 based on the number of days each FF and U factor was in effect during the Prior Year at issue.

	Percent	Calculation
Prior Year FF Factor:	0.92057%	((L1 FF Factor * L1 Days) + (L2 FF Factor * L2 Days))/(L1+L2 Days)
Prior Year U Factor:	0.24076%	((L3 U Factor * L3 Days) + (L4 U Factor * L4 Days))/(L3+L4 Days)

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

Inputs are shaded yellow

Line	TRR Values		Notes	Source	
1	$1,162,911,173	= Wholesale Base TRR		1-BaseTRR, Line 89	
2	-$121,378,713	= Total Wholesale TRBAA	Note 1	2018 TRBAA	ER18-154
3	-$120,967,080	= HV Wholesale TRBAA		2018 TRBAA	ER18-154
4	-$411,633	= LV Wholesale TRBAA		2018 TRBAA	ER18-154
5	-$8,215,991	= Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue	
6	97.5957%	= HV Allocation Factor		31-HVLV, Line 37	
7	2.4043%	= LV Allocation Factor		31-HVLV, Line 37	

Calculation of Total High Voltage and Low Voltage components of Wholesale TRR

		Col 1	Col 2	Col 3	
		TOTAL	High Voltage	Low Voltage	Source
8	**Wholesale Base TRR:**	$1,162,911,173	$1,134,951,175	$27,959,999	See Note 3
9	**CWIP Component of Wholesale Base TRR:**	$28,424,758	$28,424,758	$0	See Note 4
10	**Non-CWIP Component of Wholesale Base TRR:**	$1,134,486,415	$1,106,526,417	$27,959,999	See Note 5
11	**Wholesale TRBAA:**	-$121,378,713	-$120,967,080	-$411,633	Lines 2 to 4
12	**Less Standby Transmission Revenues:**	-$8,215,991	-$8,018,453	-$197,538	See Note 6
13	**Components of Wholesale Transmission Revenue Requirement:**	$1,033,316,470	$1,005,965,642	$27,350,828	Sum of Lines 8, 11, and 12

Notes:

1) TRBAA is "Transmission Revenue Balancing Account Adjustment". The TRBAA is determined pursuant to SCE's Transmission Owner Tariff and may be revised each January 1, upon commission acceptance of a revised TRBAA amount, or upon the date the Commission orders.
2) From 33-RetailRates. See Line: Line 17, column 3
3) Column 1 is from Line 1.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.
4) From 24-CWIPTRR, Line 88. All High Voltage.
5) Line 8 - Line 9
6) Column 1 is from Line 5.
   Column 2 equals Column 1 * Line 6.
   Column 3 equals Column 1 * Line 7.

Calculation of SCE Wholesale Rates (See Note 1)

SCE's wholesale rates are as follows:

1) Low Voltage Access Charge
2) High Voltage Utility-Specific Rate
3) HV Existing Contracts Access Charge

Calculation of Low Voltage Access Charge:

Line				Source
1	LV TRR =	$27,350,828		29-WholesaleTRRs, Line 13, C3
2	Gross Load =	88,026,785	MWh	32-Gross Load, Line 3
3	Low Voltage Access Charge =	$0.00031	per kWh	Line 1 / (Line 2 * 1000)

Calculation of High Voltage Utility Specific Rate:
(used by ISO in billing of ISO TAC)

Line				Source
4	SCE HV TRR =	$1,005,965,642		29-WholesaleTRRs, Line 13, C2
5	Gross Load =	88,026,785	MWh	32-Gross Load, Line 3
6	High Voltage Utility-Specific Rate =	$0.0114279	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

Line				Source
7	HV Wholesale TRR =	$1,005,965,642		29-WholesaleTRRs, Line 13, C2
8	Sum of Monthly Peak Demands:	163,348	MW	32-Gross Load, Line 4
9	HV Existing Contracts Access Charge:	$6.16	per kW	Line 7 / (Line 8 * 1000)

Notes:
1) SCE's wholesale rates are subject to revision upon acceptance by the Commission of a revised TRBAA amount. See Note 1 on 29-WholesaleTRRs.

Derivation of High Voltage and Low Voltage Gross Plant Percentages

Determination of HV and LV Gross Plant Percentages for ISO Transmission Plant in accordance with ISO Tariff Appendix F, Schedule 3, Section 12.

Input cells are shaded yellow

A) Total ISO Plant from Prior Year

HV and LV Components of Total ISO Plant on Lines 2, 3, 7, 8, and 9 are from the Plant Study, performed pursuant to Section 9 of Appendix IX:

Line	Classification of Facility:	Total ISO Gross Plant	Land	Structures	HV Land	LV Land	HV Structures	LV Structures	HV/LV Transformers
1	**Lines:**								
2	HV Transmission Lines	$4,365,608,275	$207,236,614	$4,158,371,661	$207,236,614	$0	$4,158,371,661	$0	$0
3	LV Transmission Lines	$90,835,004	$5,567,060	$85,267,944	$0	$5,567,060	$0	$85,267,944	$0
4	**Total Transmission Lines (L 2 + L 3):**	$4,456,443,279	$212,803,674	$4,243,639,605	$207,236,614	$5,567,060	$4,158,371,661	$85,267,944	$0
5									
6	**Substations:**								
7	HV Substations (>= 200 kV)	$3,366,536,505	$39,025,671	$3,327,510,835	$39,025,671	$0	$3,327,510,835	$0	$0
8	Straddle Subs (Cross 200 kV boundary):	412,135,343	$189,495	$411,945,848	$122,642	$66,854	$221,615,455	$119,031,510	$71,298,883
9	LV Substations (Less Than 200kV)	41,455,168	$153,791	$41,301,377	$0	$153,791	$0	$41,301,377	$0
10	**Total all Substations (L7 + L8 + L9)**	$3,820,127,016	$39,368,957	$3,780,758,060	$39,148,312	$220,644	$3,549,126,290	$160,332,887	$71,298,883
11									
12	**Total Lines and Substations**	$8,276,570,295	$252,172,630	$8,024,397,665	$246,384,926	$5,787,704	$7,707,497,951	$245,600,831	$71,298,883
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant that can directly be determined to be HV or LV:				
18	Land	$246,384,926	$5,787,704	$252,172,630	From above Line 12
19	Structures	$7,707,497,951	$245,600,831	$7,953,098,782	From above Line 12
20	Total Determined HV/LV:	$7,953,882,877	$251,388,535	$8,205,271,412	Sum of lines 18 and 19
21	Gross Plant Percentages (Prior Year):	96.936%	3.064%		Percent of Total
22					
23	Straddling Transformers	$69,114,467	$2,184,415	$71,298,883	Straddling Transformers split by Gross Plant Percentages on Line 21
24	Abandoned Plant (BOY)	$37,069,049	-$37,069,049	$0	Total: 12-Abandoned Plant Line 2, HV: 12-Abandoned Plant Line 5, LV = Total - HV
25	Total HV and LV Gross Plant for Prior Year	$8,060,066,393	$216,503,902	$8,276,570,295	Line 20 + Line 23 + Line 24
26					
27					

28 B) Gross Plant Percentage for the Rate Year:

Line		High Voltage	Low Voltage	Total	Notes:
29					
32	Total HV and LV Gross Plant for Prior Year	$8,060,066,393	$216,503,902	$8,276,570,295	Line 25
33	In Service Additions in Rate Year:	$633,745,813	$516,245	$634,262,057	13-Month Average: 16-PlantAdditions, Line 25, Cols 7 (for Total) and 12 (for LV). HV = C7 - C12.
34	CWIP in Rate Year	$115,461,165	$0	$115,461,165	13 Month Average: 10-CWIP, Line 54, Col. 8
35	Total HV and LV Gross Plant for Rate Year	$8,809,273,371	$217,020,147	$9,026,293,518	Line 32 + Line 33 + Line 34
36					
37	HV and LV Gross Plant Percentages:	97.596%	2.404%		Percent of Total on Line 35
38	(HV Allocation Factor and				
39	LV Allocation Factor)				

Calculation of Forecast Gross Load

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	88,010,855		Note 1
2	Pump Load forecast:	15,930		Note 2
3	Forecast Gross Load:	88,026,785	Line 1 + Line 2	Sum of above
4	Forecast 12-CP Retail Load:	163,348		Note 1

Notes:
1) Latest SCE approved sales forecast as of April 15 of each year.
2) SCE pump load forecast as of April 15 of each year.
3) The load forecast used in Schedule 32 shall be for the calendar year in which the rates are to be in effect.

Calculation of SCE Retail Transmission Rates

	Source	
Retail Base TRR: 1,169,306,623	1-BaseTRR WS, Line 86	**Input cells are shaded yellow**

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12	Col 13	Col 14
		Note 1		Note 2	Note 3	Note 4	Note 5	Note 6	Note 7		Note 8	Note 8	Note 8		
				Sales Forecast Billing Determinants:											
			= Retail Base TRR * Line1:Col1	Sales Forecast (Not Including Backup)	Sales Forecast (Backup)	NEM Adjustment	Applies to supplemental kW demand charges	Applies to contracted standby kW demand charges	= (Line1:Col3 + Line1:Col4) - Line1:Col5	= Line1:Col2 / (Line1:Col8*10^6)	= Line1:Col2 / ((Line1:Col6 + Line1:Col7)*10^3)	Determinants: to be applied to the Supplemental kW demand charges,			
Line	**CPUC Rate Group**	**12-CP factors**	**Total Allocated costs**	**GWh**	**Backup GWh**	**NEM GWh**	**Maximum demand - MW**	**Standby demand - MW**	**Billing Determinants with NEM Adjustment**	**Total energy rate - $/kWh**	**Total demand rate - $/kW-month**	**GWh**	**Maximum demand - MW**	**Standby demand - MW**	**Notes**
1a	Domestic	40.94%	$478,746,782	28,329		892	0	0	27,437	$0.01745					
1b	GS-1	7.54%	$88,176,483	5,802		9	0	2	5,793	$0.01522		5,989	28,839	2	
$1b_2$	GS-1 continued								0		$3.16	$91,171,458	$3.16		Notes 9,10
1c	TC-1	0.05%	$570,989	58			0		58	$0.00979					
1d	GS-2	17.48%	$204,377,946	14,128			48,592	34	14,128		$4.20				
1e	TOU-GS-3	9.26%	$108,329,087	8,081			23,361	69	8,081		$4.62				
1f	TOU-8-SEC	8.85%	$103,522,712	8,220			20,973		8,220		$4.94				
1g	TOU-8-PRI	5.73%	$67,029,174	5,440			12,707		5,440		$5.27				
1h	TOU-8-SUB	6.30%	$73,677,647	5,934			12,225		5,934		$6.03				
1i	TOU-8-Standby-SEC	0.09%	$1,081,307	122	101		351	311	223		$1.63				
1j	TOU-8-Standby-PRI	0.19%	$2,212,910	560	231		1,361	1,411	790		$0.80				
1k	TOU-8-Standby-SUB	0.39%	$4,533,122	1,644	600		3,159	8,422	2,244		$0.39				
1l	TOU-PA-2	1.53%	$17,934,824	1,795			7,554	1	1,795		$2.37				
1m	TOU-PA-3	1.16%	$13,509,075	1,456			4,828	7	1,456		$2.79				
1n	Street Lighting	0.48%	$5,604,566	726			0		726	$0.00772					
1o	---								0						
2	Totals:	100.00%	$1,169,306,623	82,296	932	901	135,110	10,258	82,326						
3															
4															

5 **2) Determination of Demand Rates for Large Power (TOU-8) Rate Groups**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
7		from Line1:Col2	from Line1:Col7	= Col1 / Col2 / 10^3			from Line1:Col2	Note 11	= Col 6 / (Col 7 * 10^3)
8									
9	**CPUC Rate Group**	**Standby Allocated costs**	**Standby Demand - MW**	**Contracted Standby Demand Charge $/kW**		**CPUC Rate Group**	**Non-Standby Allocated Costs**	**Sum of Standby and Non-Standby Demand**	**Supplemental kW demand Charge $/kW**
9a	TOU-8-Standby-SEC	$1,081,307	311	$3.48		TOU-8-SEC	$103,522,712	21,324	4.85
9b	TOU-8-Standby-PRI	$2,212,910	1,411	$1.57		TOU-8-PRI	$67,029,174	14,068	4.76
9c	TOU-8-Standby-SUB	$4,533,122	8,422	$0.54		TOU-8-SUB	$73,677,647	15,384	4.79
9d	---					---			
10									

11 **3) End-User Transmission Rates**

12		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10
13		= Col 2 + Col 3	= Line1:Col2 - Line16:Col3	= Line16:Col7 * Line1:Col7 *10^3		= Line16:Col2 / (Line1:Col8 * 10^6)	= Line16:Col2 / Line1:Col6 / 10^3	from Line9:Col3	= Line16:Col6 * 0.746	= Line16:Col7 * 0.746	
14			Note 12				Note 13	Note 14			
15	**CPUC Rate Group**	**Total Revenues**	**Revenue associated with Supplemental Demand or Energy**	**Standby Demand Revenue**		**Energy Charge - $/kWh**	**Supplemental Demand Charge - $/kW-month**	**Contracted standby kW demand Charge - $/kW-month**	**Supplemental Demand Charge - $/HP-month**	**Contracted standby kW demand Charge - $/HP-month**	**Notes**
16a	Domestic	$478,746,782	$478,746,782			$0.01745					
16b	GS-1	$88,176,483	$88,169,693	$6,790		$0.01522	$3.16	$3.16			Note 15
16c	TC-1	$570,989	$570,989			$0.00979					
16d	GS-2	$204,377,946	$204,258,277	$119,669			$4.20	$3.48			
16e	TOU-GS-3	$108,329,087	$108,090,625	$238,461			$4.63	$3.48			
16f	TOU-8-SEC	$101,819,091	$101,819,091				$4.85				
16g	TOU-8-PRI	$60,546,719	$60,546,719				$4.76				
16h	TOU-8-SUB	$58,547,430	$58,547,430				$4.79				
16i	TOU-8-Standby-SEC	$2,784,927	$1,703,621	$1,081,307			$4.85	$3.48			
16j	TOU-8-Standby-PRI	$8,695,365	$6,482,455	$2,212,910			$4.76	$1.57			
16k	TOU-8-Standby-SUB	$19,663,338	$15,130,216	$4,533,122			$4.79	$0.54			
16l	TOU-PA-2	$17,934,824	$17,931,710	$3,114			$2.37	$2.37	$1.77	$1.77	Note 16
16m	TOU-PA-3	$13,509,075	$13,488,458	$20,618			$2.79	$2.79			
16n	Street Lighting	$5,604,566	$5,604,566			$0.00772					
16o	---										
17	Totals:	$1,169,306,623	$1,161,090,632	$8,215,991							

18

19 **Notes:**

1) See Col 9 of Lines 35a, 35b, 35c, etc.
2) Sales forecast in total Giga-watt hours usage, represents the customers' total annual GWh usage. Based on same forecast as Gross Load forecast in Schedule 32, Line 1, but at customer meter level.
Does not include Backup GWh included in Column 4 (the sum of Column 3 and 4 equals total Sales Forecast).
3) Backup GWh represents the amount of electric service that is provided by SCE to a customer who has an onsite generating facility during unscheduled outages of the customer’s on-site generator.
Only applies to TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups.
4) Amount of energy included in the sales forecast that is not subject to transmission charges pursuant to the California Public Utilities Commission (“CPUC”) approved Net Energy Metering Program.
5) Sales forecast pertaining to the sum of monthly maximum supplemental Mega-watt demand, applies to demand charge schedules
6) Sales forecast pertaining to the sum of monthly contracted standby Mega-watt demand, applies to standby schedules
7) Net Forecast in total Giga-watt hours usage - represents the customers' annual Net GWh, applicable to Non-Demand Charge Schedules such as Residential or Small General Service
8) Recorded sales from Sample meters adjusted for population - use to set the total demand rate for the optional time-of-use schedules within the GS-1 rate group
9) Line 1b2, Col11 = Line 1b Col9 * Line 1b Col11 * 10^6
10) Total demand rate for the optional time-of-use schedules within the GS-1 rate group, Line 1b2:Col10 = Line 1b2:Col12 (which = Line 1b2:Col11 / ((Line1b:Col12 + Line1b:Col13) * 10^3)
11) Sum of the TOU-8 Standby and TOU-8 Non-Standby billing determinants in Line1:Col6
12) For TOU-8 Rates revenue = Supplemental Demand Charge on Line 9 Column 8 * Maximum Demand on Lines 1 Column 6
13) For optional time-of-use schedules within the GS-1 rate group (Line16b:Col6), = (Line1b$_2$:Col11 - Line16:Col3) / Line1b:Col12 / 10^3
14) For the non TOU-8-Standby rate group, it is the minimum of Line16i:Col7, or the total demand rate in Line1:Col109
15) Applicable to time-of-use schedules within the GS-1 rate group
16) Applicable to the optional schedules that contain horse power charge such as PA-1
17) GWh for TOU-8-Standby-SEC, TOU-8-Standby-PRI, TOU-8-Standby-SUB Rate Groups are placed in TOU-8-SEC, TOU-8-PRI, TOU-8-SUB Rate Groups respectively.

20

21

22 **Rate Schedules in each CPUC Rate Group:**
23
24

Line	CPUC Rate Group	Rate Schedules included in Each Rate Group in the Rate Effective Period
25	CPUC Rate Group	Rate Schedules included in Each Rate Group in the Rate Effective Period
26a	Domestic	Includes Schedules D, D-CARE, D-FERA,TOU-D-T, TOU-EV-1, TOU-D-TEV, DE, D-SDP, D-SDP-O, DM, DMS-1, DMS-2, DMS-3, and DS.
	Domestic (con't)	D (Option CPP), D-CARE (Option CPP), TOU-D-Option A, TOU-D-Option B, TOU-D-3
26b	GS-1	Includes Schedules GS-1, TOU-EV-3, and TOU-GS-1 (Option A, B, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26c	TC-1	Includes Schedules TC-1, Wi-Fi-1, and WTR.
26d	GS-2	Includes Schedules GS-2, TOU-EV-4, and TOU-GS-2 (Option A, B, R, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26e	TOU-GS-3	Includes Schedules TOU-GS-3-CPP, and TOU-GS-3 (Option A, B, R, RTP, SOP, Standby, TOU-BIP, GS-APS, GS-APS-E, and ME).
26f	TOU-8-SEC	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26g	TOU-8-PRI	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26h	TOU-8-SUB	Includes Schedules TOU-8-CPP, TOU-8-RBU, and TOU-8 (Option A, B, R, RTP, TOU-BIP, GS-APS, GS-APS-E, Backup-B, and ME).
26i	TOU-8-Standby-SEC	Includes Schedules TOU-8-Standby (Option B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26j	TOU-8-Standby-PRI	Includes Schedules TOU-8-Standby (Option A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26k	TOU-8-Standby-SUB	Includes Schedules TOU-8-Standby (Option A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26l	TOU-PA-2	Includes Schedules PA-1, PA-2, TOU-PA-ICE, and TOU-PA-2 (Option A, B, RTP, SOP-1, SOP-2, CPP, Standby, and AP-I).
26m	TOU-PA-3	Includes Schedules TOU-PA-3-CPP, and TOU-PA-3 (Option A, B, RTP, SOP-1, SOP-2, Standby, and AP-I).
26n	Street Lighting	Includes Schedules AL-2, AL-2-B, DWL, LS-1, LS-2, LS-3, LS-3-B, and OL-1.
26o	---	

27
28
29 **Recorded 12-CP Load Data by Rate Group (MW)**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
31					= Line35:(Col1+Col2 +Col3)/3			from Line1:Col3 Note 17	from Line1:Col4	= Col 7 + Col 8	= Line35:(Col4*Col5 /Col6*Col9)	= Line35:(Col10 / total of Col10)
32												
33		12-CP MW									MW	
34	CPUC Rate Group	2013	2014	2015	3-Year Average	Line losses	Recorded GWh (Average)	Standby Adjusted Sales Forecast - GWh	Backup GWh	Total Sales Forecast - GWh	Loss Adjusted Average 12-CP	12-CP Allocation factors
35a	Domestic	70,485	68,997	70,775	70,085	1.0905	29,614	28,329	0	28,329	73,112	40.94%
35b	GS-1	10,516	12,145	12,889	11,850	1.0909	5,569	5,802	0	5,802	13,466	7.54%
35c	TC-1	86	85	83	85	1.0917	62	58	0	58	87	0.05%
35d	GS-2	30,349	30,524	30,626	30,500	1.0905	15,056	14,128	0	14,128	31,212	17.48%
35e	TOU-GS-3	15,670	16,197	16,184	16,017	1.0900	8,528	8,081	0	8,081	16,544	9.26%
35f	TOU-8-SEC	14,864	15,190	14,907	14,987	1.0909	8,627	8,342	0	8,342	15,810	8.85%
35g	TOU-8-PRI	9,813	9,949	9,882	9,881	1.0644	6,165	6,000	0	6,000	10,236	5.73%
35h	TOU-8-SUB	11,037	11,843	10,984	11,288	1.0315	7,842	7,578	0	7,578	11,252	6.30%
35i	TOU-8-Standby-SEC	100	101	143	115	1.0911	77	0	101	101	165	0.09%
35j	TOU-8-Standby-PRI	269	294	311	292	1.0645	212	0	231	231	338	0.19%
35k	TOU-8-Standby-SUB	450	587	631	556	1.0316	497	0	600	600	692	0.39%
35l	TOU-PA-2	3,095	3,189	3,024	3,103	1.0910	2,218	1,795	0	1,795	2,739	1.53%
35m	TOU-PA-3	1,713	1,846	1,833	1,797	1.0896	1,382	1,456	0	1,456	2,063	1.16%
35n	Street Lighting	878	812	660	783	1.0938	727	726	0	726	856	0.48%
35o	---											
36	Totals:	169,324	171,759	172,933	171,339		86,576	82,296	932	83,227	178,571	100.00%

Determination of Unfunded Reserves

Line					
1					
2					
3					**Prior Year**
4		**Reference**			**Amount**
5					
6	**Unfunded Reserves (EOY):**	(Line 17, Col 2)			-$11,279,549
7	**Unfunded Reserves (Average BOY/EOY):**	(Line 17, Col 3)			-$12,414,249
8					
9			**Col 1**	**Col 2**	**Col 3**
10			**Prior Year**	**Prior Year**	**Prior Year**
11			**BOY**	**EOY**	**Average**
12	**Description of Issue**		**Unfunded**	**Unfunded**	**Unfunded**
13	**Unfunded Reserves**		**Reserves**	**Reserves**	**Reserves**
14	Provision for Injuries and Damages	(Line 24)	-$9,144,880	-$7,075,161	-$8,110,021
15	Provision for Vac/Sick Leave	(Line 29)	-$3,804,793	-$3,624,314	-$3,714,554
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	-$599,276	-$580,074	-$589,675
17	Totals:	(Line 14 + Line 15 + Line 16)	-$13,548,949	-$11,279,549	-$12,414,249
18					
19	**Calculations**				
20					Average
21	**Injuries and Damages**		BOY	EOY	BOY/EOY
22	Injuries and Damages - Acct. 2251010	Company Records - Input (Negative)	-$148,335,417	-$114,763,336	
23	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.1650%	6.1650%	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	-$9,144,880	-$7,075,161	-$8,110,021
25					
26	**Vacation Leave**				
27	Vacation and Personal Time Accruals - Acct. 2350080	Company Records - Input (Negative)	-$61,716,010	-$58,788,541	
28	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.1650%	6.1650%	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	-$3,804,793	-$3,624,314	-$3,714,554
30					
31	**Supplemental Executive Retirement Plan**				
32	Supplemental Executive Retirement Plan	Company Records - Input (Negative)	-$19,441,230	-$18,818,284	
33	Times:	Applicable Rate Base Percentage	50%	50%	
34	Sub-Total Supplemental Executive Retirement Plan	(Line 32 x Line 33)	-$9,720,615	-$9,409,142	
35	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	6.1650%	6.1650%	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	-$599,276	-$580,074	-$589,675

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-5

EXHIBIT TO THE TESTIMONY OF
MR. BERTON J. HANSEN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

EXHIBIT SCE-5

FORMULA SPREADSHEET REVISIONS*

1) Substantive Changes:

Schedule/Location	Description of Change	Supporting Witness
Sch. 1, old Line 84	Eliminate "Initial Prior Year" Toggle.	Hansen SCE-3
Sch. 1, Lines 19, 24-30	Allow Free Form references for all other tax items.	Lopez SCE-11
Sch. 1, Note 1	Add Note 1 to allow exclusion of other taxes costs if appropriate, renumber Notes 2-4	Hansen SCE-3
Sch. 1, Line 7 Sch. 4, Line 7	Revise Cash Working Capital to 1/8 * (O&M + A&G).	Gunn SCE-7
Sch. 1, Line 50	Revise Return on Equity to 10.8%.	Hunt SCE-17
Sch. 1, Lines 37-56	Revise cost of capital calculations	Hunt SCE-17
Sch. 1, Line 61 and Note 3	Allow "Investment Tax Credit Flowed Through" amount on Line 61 to change beginning with the Prior Year of 2019.	Lopez SCE-11
Sch. 3 (entire)	Revise the entire schedule to: 1) Simplify operation, reducing three years of costs and revenues presentation to only the one year actually needed (Prior Year); and 2) Reduce oscillation in the True Up Adjustment by adding Line 27 "Previous Annual Update TU Adjustment" component of True Up Adjustment.	Hansen SCE-3
Sch. 4	Delete Instruction 2 regarding Chino Hills.	Hansen SCE-3
Sch. 4	Delete "PBOPs True Up TRR Adjustment", old line 27a (No longer necessary because of separate revision on Schedule 20).	Hansen SCE-3
Sch. 4	Instruction 1, Line a: yellow shade and revise the reference to not refer to ROE on Schedule 1, but rather the decision establishing the ROE at the end of the Prior Year.	Hansen SCE-3

Sch. 5 ROR-1	Revise cost of capital calculation relating to debt and preferred stock costs	Hunt SCE-17
Sch. 5 ROR-2	Revise cost of capital calculation relating to debt and preferred stock costs	Hunt SCE-17
Sch. 5 ROR-3	All new: cost of debt calculations	Hunt SCE-17
Sch. 5 ROR-4	All new: cost of preferred stock calculations	Hunt SCE-17
Sch. 6 (entire)	Revise schedule to improve presentation of calculations and to be more consistent with Schedule 8	Gunn SCE-7
Sch. 8 (entire)	Revise schedule to revise calculations to be more consistent with Sch. 6	Gunn SCE-7
Sch. 9, Lines 14 and 805-818	Add section to address "Tax Normalization Calculation Pursuant to Treas. Reg §1.167(l)-1(h)(6); PLR 9313008; 9202029; 922404; 201717008", including revision of Average ADIT balance on Line 14.	Lopez SCE-11
Sch. 9, Instruction 3	Delete Instruction 3: "For any balances in account 190 relating to "Executive Incentive Comp" or "Executive Incentive Plan", the amount included in Column 3 "Gas, Generation or Other Related" shall be 50% of the total balance in Column 1, plus an amount equal to the "Labor Percentage Gas, Generation, or Other" shown on Line E of Instruction 1 times 50% of the total balance in Column 1. The remaining amount shall be included in Column 6 "Labor Related".	Lopez SCE-11
Sch. 9, Instruction 5	Delete Instruction 5: "For any balances in account 190 relating to stock options, the entire amount is included in Column 3 "Gas, Generation or Other Related.""	Lopez SCE-11
Sch. 10	Remove Eldorado-Ivanpah and Lugo Pisgah projects from list of CWIP projects, and reorder remaining projects. See also Schedule 14 and 24 revisions for same purpose.	Gunn SCE-7

Sch. 12, Lines 7-17	Reduce number of lines: begin with 2015 and end with 2025 Revise Note 3 for consistency	Ocegueda SCE-15
Sch. 12, new Line 5	Add Line for HV Abandoned Plant (BOY)	Ocegueda SCE-15
Sch. 13	Revise Note 1 "Remove any amounts related to years prior to 2012"	Gunn SCE-7
Sch. 14	Remove Eldorado-Ivanpah and Lugo Pisgah projects from list of CWIP projects, and reorder remaining projects. See also Schedule 10 and 24 revisions for same purpose.	Gunn SCE-7
Sch. 16	Revise Column 9 calculation for Sections 2 and 3 (Lines 26-49 and 50-73) to include the subtraction of Column 4, and also revise the column header: = Prior Month C9 - C4 + C8.	Gunn SCE-7
Sch. 17	Revise Instruction #1 to ensure that the Prior Year depreciation expense is calculated based on depreciation rates that were in effect.	Gunn SCE-7
Sch. 18	Revise depreciation rates.	Gunn SCE-7
Sch. 19	Revise allocation of O&M expense to reduce number of allocators and simplify calculation.	Moon SCE-9
Sch. 19	Delete old Note 2g: G: "Exclude any amount of ACE awards or Spot Bonuses in O&M accounts 560-592".	Moon SCE-9
Sch. 19	Delete old Note 2e (not used anymore): "Add NOIC annual payout".	Moon SCE-9
Sch. 19, Note 6 and Column 9	Delete references to protocols, since protocols no longer specify allocations (protocols were redundant with Sch. 19).	Moon SCE-9
Sch. 20, Instruction 2	Delete the exclusion of incentive compensation from A&G costs (old Instructions 2.H.1 through 2.H.6).	Mindess SCE-12

Sch. 20, Note 2	Delete first line of Note 2: "(NOIC includes Results Sharing, Management Incentive Program, and Non-Officer Executive Incentive Compensation)."	Mindess SCE-12
Sch. 20, Note 3	Revise Note 3 to insert "Prior Year Authorized PBOPs Expense Amount", Line b of Instruction 3. This ensures that PBOPs expense amount in effect during the Prior Year is used in determining A&G expense, making "PBOPS True Up TRR Adjustment" on Schedule 4 not necessary.	Mindess SCE-12
Sch. 21	Yellow-shade column E (spreadsheet column F). Allows Revenue Credit items to change classification is necessary.	Kim SCE-13
Sch. 21	Delete several no-longer-used revenue credit accounts: 1) 450 "Non-Residential Late Payment" 2) 453 "Sales of Water & Water Power - San Joaquin" 3) 453 "Sales of Water & Water Power – Headwater" 4) 453 "Miscellaneous Adjustments" 5) 454 "Joint Pole - Tariffed Process & Eng Fees – Conduit" 6) 454 "Joint Pole - Pl Attchmnt Audit - Undoc P&E Fee" 7) 456 "RTTC Revenue" 8) 456 "Other Inc/erd Party DC-ESM" 9) 456 "3rd Party-Div Tmg-Cr PPD training" 10) 456 "FTR Auction Revenue" 11) 456 "Direct Access Monthly Customer Charges" 12) 456 "Operating Miscellaneous Land & Facilities" 13) 456.1 "High Voltage Trans Access Rev (Existing Contracts)" 14) 456.1 "Scheduling/Dispatch Revenues (CSS)" 15) 417 "ECS - Pass Pole Attachments" 16) 417 "ECS - Infrastructure Leasing" 17) 418.1 "SCE Capital Company"	Kim SCE-13

	Add three revenue credit accounts: 1) 451 “Conn-Charge – Residential” 2) 451 “Conn-Charge - Non-Residential” 3) 451 “Conn-Charge - At Pole”	
Sch. 22	Revise lines 2, 6, and 11 to be calculated amounts instead of yellow-shaded amounts. Makes lines 4, 8, and 13 not necessary, and they are deleted. References revised accordingly.	Ocegueda SCE-15
Sch. 24	Remove Eldorado-Ivanpah and Lugo Pisgah projects from list of CWIP projects, and reorder remaining projects. See also Schedule 10 and 14 revisions for same purpose.	Ocegueda SCE-15
Sch. 24, Lines 51-61 and Note 3	Include Uncollectibles on TUTRR calculation. Also revise Note 3 to include Uncollectibles.	Hansen SCE-3
Sch. 25, Lines 6, 25, 27, 28, 31, 36	Use term "dues" rather than "expenses" for all EEI and EPRI dues.	Hansen SCE-3
Sch. 25, Line 28	Add “Note 5” to Notes and Instructions Column	Hansen SCE-3
Sch. 25, Lines 37 and Note 6	Include “Additional Expense Difference” on Line 37 to allow additional expenses to be excluded from Wholesale TRR if appropriate. Also add Note 6 explaining purpose of Line 37.	Hansen SCE-3
Sch. 26	Eliminate all states besides California in state tax rate calculation.	Lopez SCE-11
Sch. 27	Delete all but four allocation factors for O&M expense calculation (see consistent revisions to Schedule 19).	Moon SCE-9
Sch. 27, Lines 17 and 19	Add "- ISO" (General Plant - ISO), same for intangible plant	Ocegueda SCE-15
Sch. 28, Instruction 3	Fix Instruction #3 math so it works for leap years.	Mindess SCE-12
Sch. 30	Delete LV Wheeling Access Charge and the LVECAC. See also consistent revisions to Appendix II of TO Tariff.	Hansen SCE-3

Sch. 31	Revise HV Abandoned Plant to be based on BOY rather than EOY.	Moon SCE-9
Sch. 35	Delete entire schedule.	Hansen SCE-3

2) Typos and other non-substantive changes:

Schedule/Location	Description of Change	Supporting Witness
Table of Contents	Delete Schedule 35 from Table of Contents	Hansen SCE-3
Sch. 1, Line 16	Revise Line 15a to 16, and renumber remaining lines	Hansen SCE-3
Sch. 4	Renumber lines to eliminate "a" in 15a and 27a	Hansen SCE-3
Sch. 8, Note 1	Correct spelling in Note 1, add “on” to clarify note.	Gunn sCE-7
Sch. 20	Fix typo on Instruction 2.g.3: “or” instead of “of”.	Mindess SCE-12
Sch. 22	Add names to accounts 242 and 252 on lines 3,6, and 10	Ocegueda SCE-15
Sch. 25, between Lines 6 and 7	Fix typo on 1a: fix double “with”	Hansen SCE-3
Sch. 33	Add "MW" to Line 33, Column 10 header	Thomas SCE-16
All Schedules	Replace any instance of “Rate Effective Period” with “Rate Year” to align with defined protocol term.	Hansen SCE-3
All Schedules	Revise line numbers as appropriate	Hansen SCE-3

*Relative to the currently-effective Formula Spreadsheet (Appendix IX, Attachment 2 of SCE’s Transmission Owner Tariff). The currently-effective Formula Spreadsheet tariff is as filed and approved in Docket No. ER17-914, effective date of January 1, 2018.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-6

EXHIBIT TO THE TESTIMONY OF MR. BERTON J. HANSEN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

EXHIBIT SCE-6

Formula Protocol Revisions*

Protocol Section	Description of Change**
Section 1 and others	Refer to the current Formula Rate (effective 2012 through 2017) as the “Original Formula Rate”
Footnote 1	Revise footnote to refer to thirty-four schedules rather than thirty-five.
Section 1	Revise language re “EEI Dues and EPRI Expenses” to be EEI Dues and EPRI Dues.
Section 2	Delete Formula Rate termination date language: “the Formula Rate shall terminate December 31, 2017.”
Footnote 3	Revise to eliminate reference to ER11-3697.
Section 3, Footnote 4	Revise to refer to Prior Year rather than Rate Year: “Material Accounting Changes” shall mean any material change in SCE’s (i) accounting policies and practices from those in effect for the Prior ~~Rate~~ Year upon which the immediately preceding Annual Update was based, or (ii) internal corporate cost allocation policies or practices from those policies and/or practices in effect for the Prior ~~Rate~~ Year upon which the immediately preceding Annual Update was based.
3.a.7	Revise term “Rate Year” to “forecast period”.
3.a.11	Include language requiring specific workpapers for Account 930.2 costs: “The workpaper shall include, for each account 930.2 line item cost shown in FERC Form 1, the following information: 1) Total FERC Form 1 cost; 2) Amount Included; 3) Amount Excluded; and 4) Formula rate reference to the reason for the exclusion(s).
3.a.11 (old 3.a.12)	Delete requirement to include any workpapers detailing excluded incentive compensation costs.
3.a.12 (old 3.a.13)	Revise so that requirement is only “through the Rate Year” rather than “in the next five years”
3.d.3 and 3.d.7	Delete requirement to comply with the ER11-3697 settlement: “and (h) whether SCE's implementation of the Formula Rate Spreadsheet and these Protocols is consistent with the settlement approved by the Commission in Docket No. ER11-3697” As well as: “and f) its implementation of the Formula Rate Spreadsheet and these Protocols are consistent with the settlement approved by the Commission in Docket No. ER11-3697.”

3.d.8	Include provision that limits SCE obligation to correct errors in a previously-filed Annual Update by including the following underlined language: If SCE determines or concedes that a previously-filed Annual Update with a Prior Year not more than two years previous to the Prior Year of the current Annual Update contained errors …
Section 4	Revise entire section to reflect revisions to Schedule 3 of the Formula Rate Spreadsheet.
Section 6	Delete language in Section regarding the rollover of CWIP balance to Formula Rate (no longer needed).
Section 6 (insert in place of deleted section 6, see above)	Add language in protocols specifying that, while the new Formula Rate will calculate a TUTRR for 2016 and 2017 years, a separate calculation of the TUTRR using the old Formula Rate will be done, and any difference between the two will be reflected as a "One Time Adjustment". Additionally, any extension of the Original Formula Rate through part or all of 2018 will affect the 2018 True Up TRR by a weighted average (by days) of the True Up TRRs under the new and Original Formula Rate.
Section 8a	Add "the implementation of", and increase the time from thirty days to sixty days.
Section 8b and Exhibit B	Revise the current PBOPs mechanism to require an annual filing of the "Authorized PBOPs Expense Amount" in March or April. Also delete Exhibit B, since it is no longer required.
Section 8c	Revise consistent with revisions to 8e: 8c) SCE will make a single-issue Section 205 filing seeking Commission approval to put in effect conforming changes to Schedule 21 of the Formula Rate any time that the CPUC adopts revisions to the Gross Revenue Sharing Mechanism ("GRSM"). SCE will make its filing with the Commission between January 1 and March 1 of the year following the year that the CPUC Order became effective ~~by the later of either the filing date for the next Annual Update following the CPUC ruling or sixty days after the CPUC ruling~~.
Section 8e	Revise as follows: 8e) SCE will make a single-issue Section 205 filing to change the depreciation rates for General, Intangible or Distribution plant in Schedule 18 upon approval by the CPUC of revised depreciation rates for these plant categories. SCE shall make a filing at the Commission, as set forth in this section, between January 1 and March 1 of the year following the year that the CPUC Order became effective ~~by the later of either the filing date for the next Annual Update following the CPUC ruling or sixty days after the CPUC ruling~~.

Section 9	Delete the phrase regarding the Devers Mirage split: “provided, however, that the facilities affected by SCE’s Devers-Mirage split project shall not be included as Transmission Plant - ISO.”
Section 10	Revise Section 10 to refer to the Formula Rate Spreadsheet regarding the method of determining the amount of ISO O&M Expense.
Section 11a	Revise to eliminate reference to ER11-3697.
Section 11c	Delete entire section (relating to filing moratorium period).
Section 12a	Delete “Quarterly Tracking Report” requirement
Section 12b	Delete “Transfer of Control Information Submission” requirement
Section 12c	Delete “Transmission Capital Review” requirement

*Relative to the currently-effective Formula Protocols (Appendix IX, Attachment 1 of SCE’s Transmission Owner Tariff). The currently-effective Formula Protocols are as filed and approved in Docket No. ER15-1449, effective date of January 1, 2015.

** All proposed revisions to the Formula Protocols are supported by Mr. Hansen in Exhibit No. SCE-3.

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF

DAVID C. GUNN

ON BEHALF OF

SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-7)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DAVID C. GUNN

(EXHIBIT SCE-7)

Mr. Gunn supports the proposed depreciation rates for transmission plant and explains the formulas for determining many of the components of Rate Base used in determining the Prior Year Transmission Revenue Requirement ("Prior Year TRR") and the True Up Transmission Revenue Requirement ("True Up TRR"). He also describes the formula for determining the Depreciation Expense component of the Prior Year TRR and the True Up TRR, including the Wholesale Depreciation Difference and the determination of forecast additions to plant in-service and Construction Work in Progress ("CWIP") utilized in determining the Incremental Forecast Period Transmission Revenue Requirements ("IFPTRR") component of the Base Transmission Revenue Requirements ("Base TRR").

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER18-______-000**

PREPARED DIRECT TESTIMONY OF
DAVID C. GUNN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is David C. Gunn, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am currently a Project Manager in SCE's Capital Asset Analytics Department. As such, I am responsible for forecasting rate base and depreciation expense, supporting depreciation studies, and developing testimony and workpapers in support of SCE's filings with the CPUC and FERC.

Q. Briefly describe your education and professional background.

A. I have a Bachelor of Science degree in Business Administration, with an emphasis in Accounting from California State University, Los Angeles. Prior to my current role I worked in the Plant Accounting organization and my primary responsibility was designing metrics and modeling tools supporting SCE's goals of timely and accurate work order accounting. I started in my current position as a Project Manager at SCE in March of 2016.

Q. Have you submitted testimony to the Commission previously?

A. No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to:

1) support the proposed depreciation rates for transmission plant included in the proposed Formula Rate as shown on Schedule 18;
2) explain the formulas for determining many of the components of Rate Base used in determining the Prior Year Transmission Revenue Requirement ("Prior Year TRR") and the True Up Transmission Revenue Requirement ("True Up TRR") on Schedules 6, 8, 10, 11, 13, and 34;
3) explain the formula for determining the Depreciation Expense component of the Prior Year TRR and the True Up TRR, including the Wholesale Depreciation Difference on Schedule 17 and 25; and
4) explain the determination of forecast additions to plant in-service and Construction Work in Progress ("CWIP") utilized in determining the Incremental Forecast Period Transmission Revenue Requirements ("IFPTRR") component of the Base Transmission Revenue Requirements ("Base TRR") on Schedules 10 and 16.

Q. Does your testimony address any changes in the proposed Formula Rate?

A. Yes. My testimony covers three changes SCE is proposing in its Formula Rate: 1) SCE proposes to update its Transmission Plant depreciation rates from the currently authorized FERC rates to the same as those filed in its 2018 California Public Utilities Commission ("CPUC") General Rate Case ("GRC") (discussed in Chapter I); 2) the monthly depreciation reserves used for calculating the True Up TRR will use a new shaping mechanism (discussed in Chapter II); and 3) forecast incremental net plant in service will be offset by forecast removal costs to improve forecast accuracy (discussed in Chapter II). All three issue are described in greater detail within my testimony.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 1 (Base TRR), Line 7 relating to Cash Working Capital, Schedule 6 (Plant in Service), Schedule 8 (Accumulated Depreciation), Schedule 10 (CWIP), Schedule 13 (Working Capital), a portion of Schedule 14 (Incentive Plant) relating to Net Plant in Service for Incentive Projects (Lines 39-182), Schedule 16 (Plant Additions), Schedule 17 (Depreciation), Schedule 18 (Depreciation Rates), and Schedule 34 (Unfunded Reserves).

I. DEPRECIATION EXPENSE

Q. Please describe Depreciation Expense.

A. Depreciation Expense is comprised of three subcomponents: 1) Depreciation Expense for Transmission Plant – ISO; 2) Depreciation Expense for Distribution Plant – ISO; and 3) Depreciation Expense for General Plant & Intangible Plant.

Q. How does the Formula Rate determine the amount of Depreciation Expense for Transmission Plant – ISO?

A. Depreciation Expense for Transmission Plant – ISO is calculated on a monthly basis at the FERC Plant Account level in Schedule 17. It is calculated by multiplying monthly depreciation expense rates (annual rate / 12) by the prior month ending balance of Transmission Plant – ISO for each account. SCE will calculate depreciation expense with the rates consistent with the depreciation study results from its pending 2018 GRC application.

Q. Does these values differ from those in the current Formula Rate?

A. Yes. While the methodology to calculate depreciation expense for Transmission Plant – ISO remains the same as the current Formula Rate, the pending proposal would update depreciation rates to be consistent with the most recent CPUC GRC depreciation rate proposals.

Q. Why is SCE proposing this change?

A. The objective of depreciation is to allocate the capital cost of assets (including their future cost to retire) over their useful life. SCE's most recent depreciation study shows that SCE's currently authorized FERC Transmission depreciation rates do not adequately allocate capital costs. To remedy this, SCE proposes to use the well supported depreciation rates developed in its most recent CPUC GRC. In its GRC filing, SCE performed a detailed study to calculate the service life, net salvage, and depreciation rate characteristics of its assets. The detailed study results represent SCE's current best estimate of the life and net salvage parameters necessary to allocate the cost of Transmission plant over its useful life. Exhibit No. SCE-8 presents SCE's GRC depreciation rate testimony, which includes a summary of the depreciation rate study.

It is worth noting that the most current depreciation study's proposal for Transmission service life is the results of SCE's first actuarial life analysis. In addition, SCE augmented its net salvage analysis with a detailed per-unit study to estimate the future cost to retire assets. For three Transmission accounts (354, 355, and 356), SCE's per-unit analysis:

1) separated investment into major sub-populations (*i.e.*, Towers supporting infrastructure above and below 220kV separately);
2) estimated the current cost to retire assets from service using 7 years of recorded history; and
3) paired the recent per-unit costs with the results of SCE's actuarial analysis to forecast the timing and level of future retirements and expected inflation for the cost to retire each unit.

SCE performed the detailed per-unit analysis on these three accounts because they represent accounts with the highest estimated future cost to retire and as a result the highest depreciation rates. Thus, the FERC plant accounts with the most negative net salvage rates (with the highest cost of removal depreciation rates) are also the most well documented and supported.

Finally, the results of study were moderated by SCE's application of "gradualism."[1] Specifically, SCE capped its depreciation rates by limiting changes in net salvage ratios to no more than 25% of the currently authorized values. As a result, SCE's depreciation rate proposal is both a conservative and well supported means of calculating Transmission Plant – ISO depreciation expense.

Q. How do SCE's GRC proposed depreciation rates compare to the depreciation rates currently authorized in its TO Formula?

A. The difference between the currently authorized FERC depreciation rates and SCE's pending GRC depreciation rate proposal is shown below. Additionally, the depreciation study composite depreciation rate result of 3.87% is shown in the column titled "Depr. Study Results." This rate is what SCE would have proposed had it not moderated its CPUC GRC request in service to gradualism.

FERC Account	Description	YE 2016 ISO Plant ($M)	TO6 Settlement Rate	Proposed Formula Rate	Depr. Study Results
350.1	Fee Land	$87	0.00%	0.00%	0.00%
350.2	Easements	$165	1.66%	1.67%	1.67%
352	Structures and Improvements	$532	2.57%	2.41%	2.40%
353	Station Equipment	$3,249	2.47%	2.84%	2.84%
354	Towers and Fixtures	$2,234	2.44%	2.73%	4.70%
355	Poles and Fixtures	$324	3.67%	2.84%	9.66%
356	Overhead Conductor & Devices	$1,236	3.05%	3.24%	5.49%
357	Underground Conduit	$186	1.65%	1.73%	1.73%
358	Underground Conductors & Devices	$82	3.87%	2.41%	2.59%
359	Roads and Trails	$182	1.56%	1.65%	1.65%
Composite	**Depreciation Rate**	**$8,277**	**2.54%**	**2.73%**	**3.87%**

Q. How does the proposed Formula Rate determine the amount of Depreciation Expense for Distribution Plant – ISO?

[1] In prior GRC's, the CPUC has moderated requested increases for net salvage accruals with the application of gradualism as a means to mitigate the rate impact to customers.

A. Depreciation Expense for Distribution Plant – ISO is calculated on an annual basis at the FERC Plant Account level in Schedule 17. It is derived by multiplying the annual depreciation expense rate by the simple Beginning of Year ("BOY") End of Year ("EOY") average of Distribution Plant – ISO. The depreciation rates for Distribution Plant – ISO accounts are based on SCE's currently-authorized California Public Utilities Commission depreciation rates. This is the same methodology used in the Original Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Depreciation Expense for General Plant & Intangible Plant?

A. Annual Depreciation Expense for General & Intangible Plant is based on total amounts of General and Intangible Plant Depreciation Expense as recorded in SCE's annual FERC Form 1 filing. The amount of General and Intangible Plant Depreciation Expense included in this proposed Formula Rate is equal to these total amounts of General and Intangible plant times the Transmission Wages and Salaries Allocation Factor. General & Intangible Plant Depreciation Expense is calculated in Schedule 17. This is the same methodology used in the Original Formula Rate.

Q. Please explain the Wholesale Depreciation Difference component of the Wholesale Base TRR.

A. The difference in retail and wholesale book depreciation reserves stems from differences in authorized depreciation rates in the respective jurisdictions prior to the implementation of the California Independent System Operator Corporation ("ISO") in 1998. Prior to 1998, FERC had authorized depreciation rates for wholesale customers that were substantially lower than those authorized by the CPUC for retail customers. To compensate for this difference, the Commission authorized the establishment of retail and wholesale adjustments to the accumulated depreciation reserve. The retail and wholesale reserve adjustments were to be amortized equally over a 27 year period. SCE's proposed Formula Rate contains both the simple average (BOY/EOY) of the reserve adjustment in Rate Base and the annual amortization included in depreciation expense for both retail and wholesale customers. The Wholesale Depreciation Difference is presented in Schedule 25, Line 32 of Exhibit No. SCE-4. This is the same methodology used in the Original Formula Rate.

II. RATE BASE

Q. Please define the Prior Year TRR and explain how it is used.

A. The Prior Year TRR represents SCE's actual cost of service in the Prior Year as recorded at end of year ("EOY"). It is calculated using inputs from SCE's FERC Form 1 from the prior year, and is supplemented by the same SCE accounting records used to populate the FERC Form 1. The Prior Year TRR is a component of the Base TRR. The Base TRR is used to set SCE's transmission rates during the Rate Year at a level that approximates SCE's actual costs to be experienced during that time. The components of the Prior Year TRR are described in detail in Mr. Hansen's testimony, Exhibit No. SCE-3. The Prior Year TRR is calculated in Schedule 1, Line 81 of the proposed Formula Rate (Exhibit No. SCE-4).

Q. Please define the True Up TRR and explain how it is used.

A. True Up TRR defines the actual transmission costs that SCE incurred during the Prior Year and is also the amount of transmission costs that SCE ultimately receives through the operation of the proposed Formula Rate. For the True Up TRR, the amount of Rate Base is determined on an average basis, rather than the EOY basis used to determine the Prior Year TRR. The True Up TRR is calculated in Schedule 4 of the proposed Formula Rate. A description of the True Up TRR is described in Mr. Hansen's testimony, Exhibit No. SCE-3.

Q. What are the components of the proposed Formula Rate used for determining the Rate Base in the Prior Year TRR and True Up TRR in the formula?

A. SCE includes the following components of Rate Base:

1) ISO Transmission Plant (Schedule 6)
2) General and Intangible Plant (Schedule 6)
3) Plant Held for Future Use (Schedule 11)
4) Abandoned Plant (Schedule 12)
5) Working Capital (Schedule 13)
6) Cash Working Capital (Schedule 1, Line 7)
7) Accumulated Depreciation Reserve (Schedule 8)
8) Construction Work in Progress (Schedule 10)
9) Other Regulatory Assets/Liabilities (Schedule 23)
10) Unfunded Reserves (Schedule 34)
11) Network Upgrade Credits (Schedule 22)
12) Accumulated Deferred Income Taxes (Schedule 9)

Q. Which of these components of the Rate Base formula are you supporting in your testimony?

A. I am supporting the following components:

1) ISO Transmission Plant (Schedule 6)
2) General and Intangible Plant (Schedule 6)
3) Plant Held for Future Use (Schedule 11)
4) Working Capital (Schedule 13)
5) Cash Working Capital (Schedule 1, Line 7)
6) Accumulated Depreciation Reserve (Schedule 8)
7) Construction Work in Progress (Schedule 10)
8) Unfunded Reserves (Schedule 34)

Mr. Ocegueda in Exhibit No. SCE-15 supports Abandoned Plant, Other Reg Assets, and Network Upgrade Credits, and Mr. Lopez in Exhibit No. SCE-11 supports the Accumulated Deferred Income Taxes component of Rate Base.

Q. What values are used in determining the Rate Base for the Prior Year TRR?

A. As discussed above, SCE's Prior Year TRR uses Rate Base calculated on an EOY basis. Mr. Hansen in Exhibit No. SCE-3 explains this aspect of the overall proposed Formula Rate.

Q. What values are used in determining the Rate Base for the True Up TRR?

A. As discussed above, SCE's True Up TRR Rate Base is calculated on a weighted average basis. In the case of "Transmission Plant – ISO," "Transmission

Depreciation Reserve – ISO," "Working Capital" (Materials and Supplies and Prepayments), and "CWIP Plant," a 13-month average balance is used. For the other components of Rate Base a simple average is calculated using Beginning of Year ("BOY") and EOY balances. Mr. Hansen in Exhibit No. SCE-3 explains this aspect of the overall proposed Formula Rate.

A. ISO Transmission Plant

Q. Please explain the ISO Transmission Plant component of Rate Base.

A. ISO Transmission Plant represents the amount of Plant-In-Service reported in SCE's annual FERC Form 1 filing that is under the Operational Control of the California Independent System Operator Corporation ("CAISO"), and whose costs are recovered through the proposed Formula Rate. SCE performs a Transmission Plant Study (Schedule 7 of Exhibit No. SCE-4) categorizing its historic investment of transmission and distribution plant as either ISO or non-ISO. For details of the study, see Mr. Moon's testimony in Exhibit SCE-9. SCE's proposed Formula Rate relies on the same calculation methodology to determine Transmission Plant – ISO as was used in the Original Formula Rate and is discussed below.

Q. How does the proposed Formula Rate determine the amount of Transmission Plant – ISO for Prior Year TRR?

A. EOY Transmission Plant ISO balances are used for Prior Year TRR based on results from the Transmission Plant Study.

Q. How does the proposed Formula Rate determine the amount of Transmission Plant – ISO for True Up TRR?

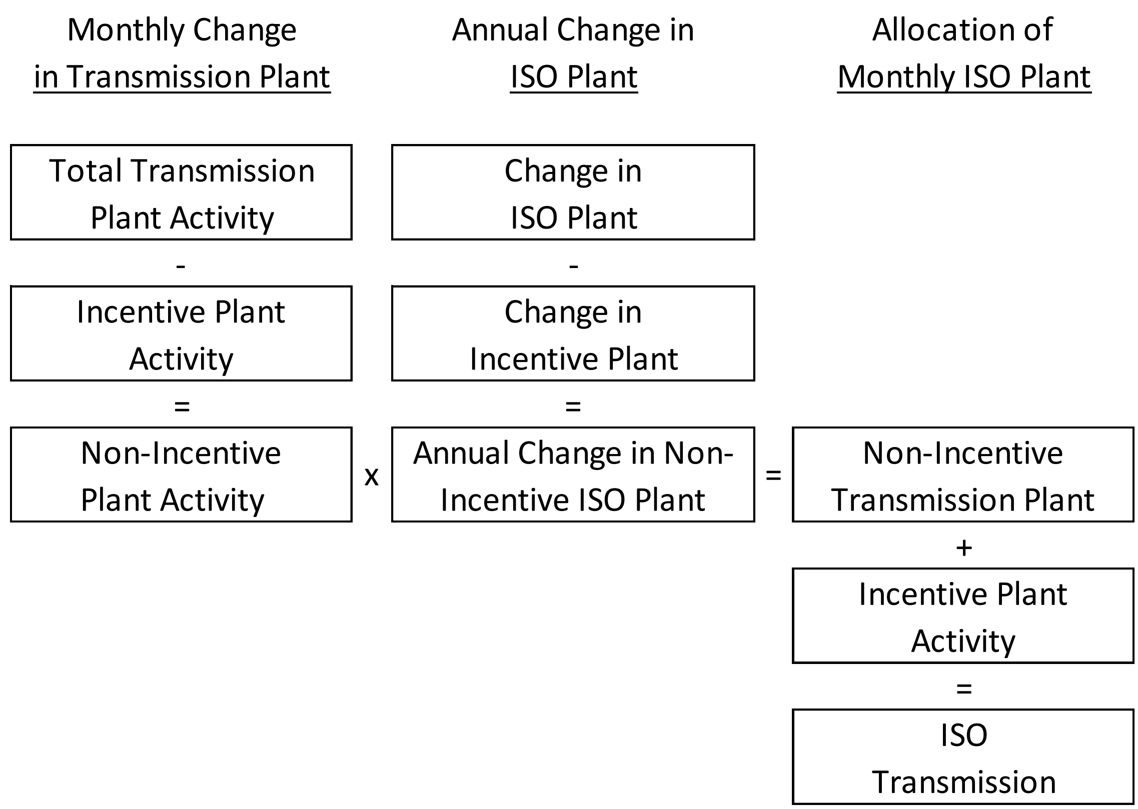
A. For True Up TRR, SCE calculates the 13-month average balance of Transmission Plant – ISO by FERC Plant Account in Schedule 6. Beginning of Year ("BOY") and End of Year ("EOY") Transmission Plant – ISO balances are sourced from the Transmission Plant Study summary. The EOY Transmission Plant – ISO balances are sourced from the Transmission Plant Study summary in Schedule 7. Because

SCE does not account for its plant on an ISO and Non-ISO basis, the monthly Transmission Plant – ISO balances (January through November) must be calculated. To do so, SCE adds to its beginning ISO balances the allocated annual change in Non-Incentive ISO Transmission Plant – ISO and incentive plant activity.[2] To determine the monthly allocation of the annual change in Non-Incentive ISO Transmission plant SCE's proposed Formula Rate uses a four step process:

1) SCE takes the difference in monthly balances to calculate monthly activity for total Transmission Plant (not jurisdictionalized).
2) From the amounts in Step 1, SCE subtracts the activity attributable to incentive plant to calculate Non-Incentive Transmission Plant activity
3) Divide resulting monthly Non-Incentive Transmission Plant activity by the annual change in Non-Incentive Plant Activity to calculate monthly allocation percent for each FERC Plant Account.
4) Multiply the annual change in Non-Incentive ISO Plant by the monthly allocation percentages calculated in Step 3 to assign annual change to each month.

The calculation of monthly balances, from beginning to end, is summarized in the diagram below.

[2] Incentive plant is treated as 100% ISO and is tracked on a monthly basis by SCE. As such, it does not require calculations to determine monthly balances. Incentive plant is available in Schedule 14 of the proposed Formula Rate (Exhibit No. SCE-4).



Q. Why is Incentive Plant treated differently in this calculation?

A. Incentive plant is treated as 100% ISO and is tracked on a monthly basis by SCE. As such, it does not require calculations to determine monthly balances. Incentive plant is available in Schedule 14 of the proposed Formula Rate (Exhibit No. SCE-4).

Q. Does this methodology represent a change from the Original Formula Rate?

A. No. The presentation of the data has changed to increase transparency and show the results of the diagram above but the shaping mechanism and calculation methodology remain the same as that used in the Original Formula Rate.

B. General and Intangible Plant

Q. Please explain the General Plant component of Rate Base in the proposed Formula Rate.

A. As indicated above, for purposes of Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, SCE determines the simple average (BOY/EOY) balance of the General Plant component of Rate Base utilizing the total amounts of General Plant reported in SCE's annual FERC Form 1 filing. The average balance of the total amount of General Plant is then allocated to the transmission Rate Base in this formula rate using the Transmission Wages and Salaries Allocation Factor. General Plant is presented in Schedule 6 of Exhibit SCE-4. This is the same methodology used in the Original Formula Rate.

Q. Please explain the Electric Miscellaneous Intangible Plant component of Rate Base in the proposed Formula Rate.

A. For purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, SCE determines the simple average (BOY/EOY) balance of the Electric Miscellaneous Intangible Plant ("Intangible Plant") component of Rate Base utilizing the total amounts of Intangible Plant reported in SCE's annual FERC Form 1 filing. The average balance of total Electric Miscellaneous Intangible Plant is then allocated to the Rate Base in this formula rate using the Transmission Wages and Salaries Allocation Factor. Electric Miscellaneous Intangible Plant is presented in Schedule 6 of Exhibit SCE-4. This is the same methodology used in the Original Formula Rate.

C. Plant Held for Future Use

Q. Please explain the Transmission Plant Held for Future Use component of Rate Base in the proposed Formula Rate.

A. Transmission Plant Held for Future Use (" PHFU") is typically comprised of land or land rights purchased in advance of Transmission Plant construction and allocation of General PHFU. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average. PHFU is analyzed at the work order level to determine land or land rights related to construction of assets intended to be placed under the Operational Control of the ISO. All work orders associated with Incentive Construction Work In Progress (Incentive CWIP) projects are excluded from this component of Rate Base. An allocated portion of General PHFU is included in transmission PHFU based on the Transmission Wages and Salaries Allocation Factor. Transmission PHFU is calculated in Schedule 11 of Exhibit No. SCE-4. The PHFU value of $9,942,155 shown on Schedule 11, Line 2a of Exhibit No. SCE-4 is an allocation of land rights for SCE's proposed Alberhill Substation. This is the same methodology used in the Original Formula Rate.

D. Working Capital

Q. Please explain the Working Capital component of Rate Base in the proposed Formula Rate.

A. Working Capital is composed of three subcomponents: 1) Materials and Supplies; 2) Prepayments; and 3) Cash Working Capital. The Materials and Supplies and Prepayments components of Working Capital are calculated in Schedule 13 of Exhibit No. SCE-4, while the Cash Working Capital is calculated in Schedule 1, Line 7 of Exhibit No. SCE-4.

Q. How does the proposed Formula Rate determine the amount of Materials and Supplies?

A. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a 13-month average and allocated in the formula rate using the Transmission Wages and Salaries Allocation Factor. Materials and Supplies BOY/EOY balances are derived using total amounts of Materials and Supplies reported in SCE's annual FERC Form 1 filing. January through November balances are derived using total amounts of Materials and Supplies sourced from SCE Records consistent with its FERC Form 1 filing. This is the same methodology used in the Original Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Prepayments?

A. Prepayments BOY and EOY balances are derived using amounts reported in SCE's annual FERC Form 1 filing. January through November balances are derived using total amounts of Prepayments from SCE Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a 13-month average and allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology used by SCE's Original Formula Rate.

Q. Has SCE performed a lead lag study for FERC working capital requirements?

A. No. While SCE has performed a lead lag study for use in its CPUC GRC, SCE has not performed a FERC specific lead lag study.

Q. Can SCE modify its GRC lead lag study to apply specifically to Transmission customers?

A. No, SCE's CPUC GRC lead lag study was performed on a total company basis and did not separate its cash working capital requirements into different business operations. Refinement of the existing study to this more granular level of detail would require an additional study to classify SCE's accounting records into specific business operations. Because SCE has not performed this study, a FERC jurisdictional lead lag study is not available.

Q. How does the proposed Formula Rate determine the amount of Cash Working Capital?

A. In light of the fact that SCE does not have a FERC jurisdictional lead lag study , the amount of cash working capital is calculated by taking 1/8 of ISO Operations and Maintenance ("O&M") Expense plus Administrative and General ("A&G")

Expense. In other words, SCE is applying the 45 day convention in the proposed Formula Rate.

Q. Is this consistent with FERC policy?

A. I understand that in the absence of a FERC jurisdictional lead lag study, it is FERC policy to apply the 45 day convention.[3]

Q. How does this differ from the Original Formula Rate methodology?

A. In the Original Formula Rate calculation, Cash Working Capital was calculated as 1/16 of ISO O&M plus A&G Expense. This is the result of the settlement agreed to by the Parties in Docket No. ER11-3697.

E. Accumulated Depreciation Reserve

Q. Please explain the Accumulated Depreciation Reserve component of Rate Base in the proposed Formula Rate.

A. Accumulated Depreciation Reserve is comprised of three subcomponents: 1) Transmission Depreciation Reserve – ISO; 2) Distribution Depreciation Reserve – ISO; and 3) General Plant & Intangible Depreciation Reserve.

Q. How does the proposed Formula Rate determine the amount of Transmission Depreciation Reserve – ISO?

A. Transmission Depreciation Reserve – ISO is the amount of accumulated depreciation associated with Transmission Plant – ISO by FERC Plant Account. It is calculated in Schedule 8. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, the value is calculated using a 13-month average balance. The BOY and EOY Transmission Depreciation Reserve – ISO balance inputs are derived from SCE's

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3 *See Carolina Power & Light Co.*, 6 FERC ¶ 61,154 at 61,296 (1979)*; Louisiana Power & Light Co.*, 14 FERC ¶ 61,075 at 61,122-23; and *Trans-Elect NTD Path 15, LLC*, 117 FERC ¶ 61,214 at 32,39-43 (2006).

Transmission Plant Study from each respective period. To develop the Transmission Depreciation Reserve – ISO balances for January through November, Transmission Depreciation Reserve – ISO activity is allocated by month using recorded monthly Total Transmission Plant activity found in Schedule 6 of Exhibit No. SCE-4. The steps used to calculate these allocation factors are described in Section A, "ISO Transmission Plant," earlier in my testimony.

Q. How does the formula differ from the methodology used in the Original Formula Rate?

A. In comparison to the Original Formula Rate, the proposed Formula Rate does not rely on allocation factors developed from recorded Transmission Reserve activity. Instead, Total Transmission Depreciation Reserve –ISO activity is allocated using Total Transmission Plant activity percentages calculated on Schedule 6 of Exhibit No. SCE-4.

Q. Why is SCE making these proposed changes?

A. Unlike plant in service, whose activity is driven largely by new additions, increases in reserve balances are driven mainly by depreciation expense. Other capital transactions that affect reserve balances, including cost of removal (increase), retirements (decrease), and gross salvage (decrease) exhibit less stable patterns in annual activity. The Original Formula Rate methodology relied on these less stable patterns to develop monthly allocation factors and would sometimes result in highly volatile allocation factors (+/- 1,000% between annual rate updates). The resulting 13-month average Transmission Depreciation Reserve – ISO balances would then reflect the results of a misaligned inter-year change that would affect SCE's calculation of True Up TRR rate base.

To remedy this, SCE will rely on the more stable Transmission Plant – ISO allocation factors calculated on Schedule 6 of the proposed Formula Rate (Exhibit No. SCE-4). These allocation factors represent a reasonable proxy for the change in reserve balances because many of the transactions that affect plant activity have associated effects on depreciation reserve activity. For example, retirements effect both plant and reserve balances equally. Similarly, cost of removal often affects the depreciation reserve at the same time that plant balances are affected by a capital addition.

In addition to offering a more stable means of allocating SCE's reserve balance, the proposed changes also offer the additional benefits of increasing formula transparency and understandability.

Q. What would have been the impact of applying this change to prior TO filings?

A. On average, the proposed change decreases SCE's average accumulated depreciation balances and results in slightly higher average rate base and revenue requirement for the True Up TRR. See the table below.

TO Filing	True Up TRR Year	Formula Rate Original	Formula Rate Proposed	Change	Affect on Rate Base
TO8	2012	$1,017	$1,028	$11	Decrease
TO9	2013	1,072	1,040	(32)	Increase
TO10	2014	1,118	1,125	7	Decrease
TO11	2015	1,246	1,252	6	Decrease
TO12	2016	1,389	1,383	(6)	Increase
Average		**1,168**	**1,166**	**(3)**	**Increase**

Q. Please provide a discussion of the change to average accumulated depreciation when this change was applied to the TO9 filing.

TO 9 Reserve Impact ($M)

Item	Original Formula Rate	Proposed Formula Rate
BOY Reserve	$1,026	$1,026
EOY Reserve	$1,061	$1,061
Allocated Average	$1,072	$1,040
Simple Average	$1,044	$1,044
Δ From Simple Average	$28	-$4

A. As shown in the table above, the average change in accumulated depreciation for Transmission – ISO in the TO9 filing was a $32 million decrease. Because accumulated depreciation is an offset to rate base, the decrease in accumulated depreciation increases the average rate base. The decrease in accumulated depreciation for Transmission – ISO is the result of an improved smoothing mechanism that, by reducing volatility in the allocators, estimates an average balance between the BOY and EOY balances. Because of the volatility in allocation factors, the Original Formula Rate resulted in an average accumulated depreciation balance *higher* than the EOY balance as shown in the table below.

As shown in the table above, the average change in accumulated depreciation for Transmission – ISO more realistically approaches the simple BOY/EOY average balance in the reserve. Excluding the effects of TO9, this improved shaping mechanism would have, on average, reduced SCE's rate base for True-Up TRR by $4.5 million.

Q. How does the proposed Formula Rate determine the amount of General Plant & Intangible Depreciation Reserve?

A. For purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average utilizing the total amount of Depreciation Reserve in SCE's annual FERC Form 1 filing. The balance is then allocated to the Accumulated Depreciation Reserve component of Rate Base in the proposed Formula Rate using the Transmission Wages and Salaries Allocation Factor. General Plant & Intangible Plant Depreciation Reserve is presented in Schedule 8 of Exhibit No. SCE-4. This is the same methodology used by SCE's Original Formula Rate.

F. Construction Work in Progress Plant – Prior Year

Q. Please explain the Construction Work In Progress Plant – Prior Year component of Rate Base.

A. Construction Work In Progress Plant – Prior Year ("CWIP -- Prior Year") is the balance of construction work in progress for Incentive Transmission projects the Commission has authorized SCE to include in rate base. It is presented in Schedule 10 of Exhibit No. SCE-4. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, it is calculated using a 13 month average. For details of SCE's approved incentive transmission projects that contribute to CWIP – Prior Year, see Mr. Moon's testimony in Exhibit SCE-9.

G. Unfunded Reserves

Q. Please explain the Unfunded Reserves component of Rate Base.

A. Unfunded Reserves is composed of three subcomponents: 1) Injuries and Damages; 2) Vacation Leave; and 3) Supplemental Executive Retirement Plan. All three subcomponents are calculated in Schedule 34 of Exhibit No. SCE-4.

Q. How does the proposed Formula Rate determine the amount of Injuries and Damages?

A. Injuries and Damages BOY/EOY balances are derived using total amounts from SCE Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average and allocated in the formula rate using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Original Formula Rate.

Q. How does the proposed Formula Rate determine the amount of Vacation Leave?

A. Vacation Leave BOY/EOY balances are derived using total amounts from SCE's

Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of the True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average and allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Original Formula Rate.

Q. How does the formula rate determine the amount of Supplemental Executive Retirement Plan?

A. Supplement Executive Retirement Plan BOY/EOY balances are derived using total amounts from SCE's Records. As indicated above, for purposes of the Prior Year TRR, the value is based on EOY balances. For purposes of True Up TRR, this component of Rate Base is calculated using a simple (BOY/EOY) average. First, the average amount is multiplied by the applicable Rate Base percentage, and then allocated using the Transmission Wages and Salaries Allocation Factor. This is the same methodology as was used in the Original Formula Rate.

III. TRANSMISSION INCENTIVE PLANT NET PLANT IN SERVICE

Q. Does the formula determine amounts of ISO Transmission Plant eligible to receive Return on Equity adders?

A. Yes. For each project for which SCE has received Commission approval to include a Return on Equity ("ROE") adder in the determination of SCE's total ROE, the formula quantifies the net plant in service eligible to receive such an adder. This amount is called "Transmission Incentive Plant Net Plant In Service." Mr. Hansen in Exhibit No. SCE-3 explains how the amount of Transmission Incentive Plant Net Plant In Service is used to calculate the dollar amount of ROE adders included in the Prior Year TRR and True Up TRR.

Q. Please describe how the formula determines Transmission Incentive Plant Net Plant-In-Service.

A. Transmission Incentive Plant Net Plant-In-Service is the amount of recorded Plant-In-Service less Accumulated Depreciation associated with projects that have received Commission authorization to receive an ROE adder. Transmission Incentive Plant Net Plant-In-Service is provided by project in Schedule 14 of Exhibit No. SCE-4. As indicated above, for purposes of the Prior Year TRR the value is based on EOY balances. For purposes of the True Up TRR, Transmission Incentive Plant Net Plant-In-Service is calculated using a 13-month average. This is the same methodology as was used in the Original Formula Rate.

IV. FORECAST INFORMATION USED IN DEVELOPING THE INCREMENTAL FORECAST PERIOD TRR ("IFPTRR")

Q. What forecasts are you supporting that will be used in the calculation of the IFPTRR?

A. I am supporting forecasts of two amounts: 1) Forecast Net Plant Additions on Schedule 16; and 2) Forecast Period Incremental CWIP on Schedule 10.

Q. How are these two forecasts used in this formula?

A. Both of these forecast amounts will be used in the calculation of the IFPTRR in Schedule 2. These forecast amounts represent balances that will be included in SCE's Rate Base during the Forecast Period, and thus contribute to SCE's Base TRR in the Forecast Period. Mr. Hansen, in Exhibit SCE-3, fully explains how they are used and contribute to the amount of the IFPTRR.

Q. What dollar amounts are included in Mr. Moon's forecast capital expenditures?

A. Mr. Moon's forecast of capital expenditures includes only the direct capital expenditures for the Transmission / Distribution Business Unit ("TDBU") for each project. Direct expenditures include costs for materials, direct TDBU labor, costs for removal, and TDBU divisional overheads. The divisional overheads are costs that support a group of construction projects within a division of the company (*i.e.*, costs that cannot be assigned to any one particular project). These costs include TDBU divisional management, TDBU administration and accounting, as well as costs for supplies and tools.

Q. Please describe how you develop the Forecast Net Plant Additions to be incorporated into the Incremental Forecast Period TRR.

A. I develop Forecast Net Plant Additions based on direct capital expenditure forecast information for projects that are expected to be placed in service by the end of the Forecast Period. Details on capital projects including SCE's annual expenditure forecast and expected completion date (s) or blanket close designation for each budget item can be found in Mr. Moon's testimony, Exhibit SCE-9. I convert the direct capital expenditures provided by Mr. Moon and the recorded CWIP balances from the last recorded year into a monthly forecast of unloaded Transmission Plant additions. SCE includes all components of construction cost as prescribed in Part 18 of the Code of Federal Regulations, Part 101, paragraph 3 of the Electric Plant Instructions (18 CFR Part 101).

Q. What are Corporate Overheads and AFUDC?

A. Corporate overheads are similar to capitalized divisional overheads; however, they support all SCE capital projects, rather than projects for a particular division of the company. Forecast capitalized corporate overheads consist of costs for Corporate Administrative & General (A&G), Pensions & Benefits (P&B), Payroll Taxes, Property Taxes, and Injuries & Damages. On Schedules 10 and 16 of Exhibit SCE-4, SCE adds a 7.5% loader to unloaded forecast additions to reflect the capitalized overheads added to construction projects.

AFUDC is the generally accepted regulatory accounting procedure to capitalize the cost of debt and equity funds used to finance the construction of capital additions. It compensates investors for the cost of supplying funds for a capital project during construction before an asset is used and useful and is added to rate base. Once in rate base, AFUDC is shut off and return can be collected from ratepayers. On Schedule 16 of Exhibit No. SCE-4, SCE adds a 3.0% loader to unloaded forecast additions to reflect the AFUDC financing costs of constructing capital projects.

SCE's methodology for applying Corporate Overheads and AFUDC is the same as the Original Formula Rate.

Q. What is Cost of Removal?

A. Cost of Removal is the capital cost required to retire assets at the end of their service life. Cost of removal is accrued (credited) to accumulated depreciation during the monthly calculation of depreciation expense. When actual removal costs are incurred, cost of removal expenditures decrease (debit) prior accruals for removal costs. Eight percent of the Non-Incentive forecast transmission capital activity are estimated to be removal related and are reclassified from Gross Plant to Accumulated Depreciation.

Q. How does SCE incorporate Corporate Overheads on Schedule 10?

A. Schedule 10 of Exhibit No. SCE-4 includes a forecast of incentive plant additions. SCE adds to the incremental Incentive activity (*i.e.*, amounts spent and/or closed during the forecast period) a corporate overhead adder of 7.50% to reflect in plant the effects of estimated corporate overheads.

Q. How does SCE incorporate Corporate Overheads, AFUDC, and Cost of Removal on Schedule 16?

A. Forecast capital activity for non-incentive Transmission Activity is entered on Schedule 16 of Exhibit No. SCE-4. SCE adjusts the incremental Non-Incentive activity by 7.50% to add Corporate Overheads. SCE reclassifies 8.00% of this loaded activity to cost of removal and correspondingly reduces the incremental reserve balances. Finally, SCE adds 3.00% to the net of removal plant additions to reflect the estimated AFUDC required to finance construction of the projects. This is the same methodology as was used in the Original Formula Rate.

Q. Does your forecast take into account changes in accumulated depreciation?

A. Yes. Schedule 16 of the proposed Formula Rate (Exhibit No. SCE-4) includes incremental depreciation accruals on forecast plant additions. Depreciation expense is added to the Incremental Reserve balance based on a composite depreciation rate of 2.73% which was calculated based on the proposed Depreciation Rates presented in Schedule 18 of Exhibit No. SCE-4, applied to EOY Transmission Plant – ISO by FERC Account. In addition to increases attributable to depreciation expense, incremental reserve balances are reduced by forecast Cost of Removal.

Q. Does this represent a change from the Original Formula Rate?

A. Yes. In order to improve forecasting accuracy the incremental reserve balances now more accurately reflect the incremental changes attributable to cost of removal closings.

Q. Why is SCE making this change?

A. Removal costs are appropriately accrued to the accumulated depreciation over the life of the assets. When incurred, removal costs will reverse these prior period accruals as an offset to the accumulated depreciation. By reducing Incremental Reserve balances by the forecast Cost of Removal, the proposed Formula Rate more accurately reflects the accounting transactions for cost of removal.

Q. Please describe how you develop the Forecast Period Incremental CWIP to be incorporated into the Incremental Forecast Period TRR.

A. SCE currently has nine projects that have been approved by the Commission for Incentive CWIP treatment. Details on the approved incentive projects including SCE's monthly capital expenditure forecast and the expected completion date(s) for each project can be found in Mr. Moon's testimony, Exhibit SCE-9. SCE's forecast of Incentive CWIP starts with recorded EOY CWIP balances. It takes the monthly capital expenditure forecast from Mr. Moon's testimony, incorporates corporate overheads using the corporate overheads loader, accumulates a monthly Incentive CWIP balance and reflects the reclassification of Incentive CWIP to

Transmission Plant as projects reach their estimated completion date. The Forecast Period Incremental CWIP is presented in Schedule 10 of Exhibit No. SCE-4.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

David C. Gunn, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

David C. Gunn

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by David Clellan Gunn, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-8

EXHIBIT TO THE TESTIMONY OF MR. DAVID GUNN

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Application No.:	A.16-09-
Exhibit No.:	SCE-09, Vol. 03
Witnesses:	P. Joseph A. Varvis R. White

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

(U 338-E)

Results of Operations
Volume 03 – Depreciation Study

Before the

Public Utilities Commission of the State of California

Rosemead, California
September 1, 2016

SCE-09: Results of Operation
Volume 03 - Depreciation Study

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I.

INTRODUCTION

Depreciation is the means by which SCE's investors recover the costs of the fixed capital investments they have made to provide electric service to SCE's customers. Depreciation provides a mechanism for recovery of the original cost of the investment and the future cost to retire the investment over its useful life. In each GRC, SCE submits a depreciation study that presents analyses of service lives and retirement costs. In Volume 2 of SCE-09, SCE set forth its proposed depreciation expense accruals for 2018-2020. This Volume 3 of SCE-09 describes the depreciation study undertaken by SCE's in-house and outside experts.

In this rate case, unlike prior ones, SCE undertook an *actuarial* analysis to estimate life parameters for its transmission and distribution (T&D) assets. Actuarial analyses rely on aged data, not on the unaged plant records that SCE used in the past to derive its proposed depreciation expense. SCE's actuarial analysis revealed that for 18 of 20 T&D accounts, the forecast service life of many assets is the same or longer than what had been authorized in the past. When service lives are extended, depreciation expense will decrease, all other things being equal.

However, a large driver impacting depreciation expense is cost of removal. As assets age, the effect of inflation increases cost of removal. Indeed, depreciation is a major expense in large part because it includes an allocation of the original cost of fixed capital and its estimated future cost of removal. This future removal cost, called net salvage, is defined as gross salvage minus cost of removal. When cost of removal is higher than gross salvage, as is commonly experienced in the utility industry, the value is negative and results in an increase to total depreciation expense. When that increasing cost to remove is expressed as a percentage of the original cost—a computation known as the net salvage ratio, or NSR—it becomes more negative as SCE's infrastructure ages.

In the 2015 GRC, the Commission directed SCE to conduct a more detailed analysis of its cost of removal for at least five of SCE's largest plant accounts as measured by proposed depreciation expense. That rigorous analysis, known as a "per-unit" analysis, differs from the traditional way in which SCE forecasts net salvage. Section C of Chapter II describes these differences in detail, but the main point is that under a per-unit analysis, SCE divides each plant account into "sub-populations" of similar assets, determines the historical cost to remove each unit in the sub-populations, and then applies the per-unit cost to the quantities identified in the surviving plant balance. SCE uses the surviving plant balance (*i.e.*, the mix of assets on SCE's books *today*) as the "window" into what future costs of removal will be, given the projected timing of the assets' retirement. This work is detailed and rigorous, and meets the Commission's compliance directives described in Chapter II. A traditional cost of removal analysis, applied to the balance of accounts, takes a more aggregated approach and generally assumes that future removal costs and activity will mimic what SCE experienced in the past. Both are accepted methods of forecasting the cost of removal, but the per-unit analysis is more detailed and labor-intensive.

The study results confirmed that SCE's NSRs are increasingly negative. That fact is not surprising given SCE's recorded history and the many other drivers SCE discusses in Section D of Chapter II. In fact, applying the results of the study would result in an estimated increase in depreciation expense of $963 million. However, SCE is not requesting to recover that sum over this GRC cycle given the resulting impact it would have on customers' retail rates. Rather, for reasons described in Section B of Chapter II, SCE elects to moderate its proposal in service of a public policy principle on which the Commission has relied before in the depreciation context—"gradualism." The idea is to spread the increases in depreciation expense over time to mitigate the immediate rate impact on customers. Thus, for T&D accounts where SCE's depreciation study results in an increase greater than 25% of currently authorized NSRs, SCE proposes to cap the increase at 25%. The result of applying this cap is to reduce SCE's proposal to $71 million above currently authorized, $892 million less than what the study results justify, as shown in Figure I-1 below.

A. Organization of Testimony

This chapter summarizes SCE's depreciation proposal comparing the "full" (un-tempered) empirical study results with SCE's moderated proposal. Section D of this chapter shows average life and NSR values for all accounts.

Sections A through C of Chapter II address the Commission's four compliance directives from SCE's 2015 GRC, which required additional quantitative detail to support SCE's net salvage proposals.[1] Section D of the same chapter offers qualitative reasons for SCE's increasingly negative net salvage rates.

Chapter III sets forth the results of SCE's depreciation study, based on plant assets as of December 31, 2015, separated into: (1) a life and net salvage analysis of Transmission and Distribution (T&D) assets, undertaken by SCE's outside expert (Section A of Chapter III); and (2) a life and net

[1] The compliance directives are also addressed in Chapter III, Section A.3.

salvage analysis of Generation assets, plus General and Intangible (G&I) assets, undertaken by SCE's in-house expert (Section B of Chapter III).

B. SCE's Depreciation Proposals

As shown in Table I-1, SCE's total proposed depreciation expense resulting from the study's revised parameters (using the moderated approach) is approximately five percent higher than recorded 2015 depreciation expense using the 2015 GRC-authorized depreciation rates.

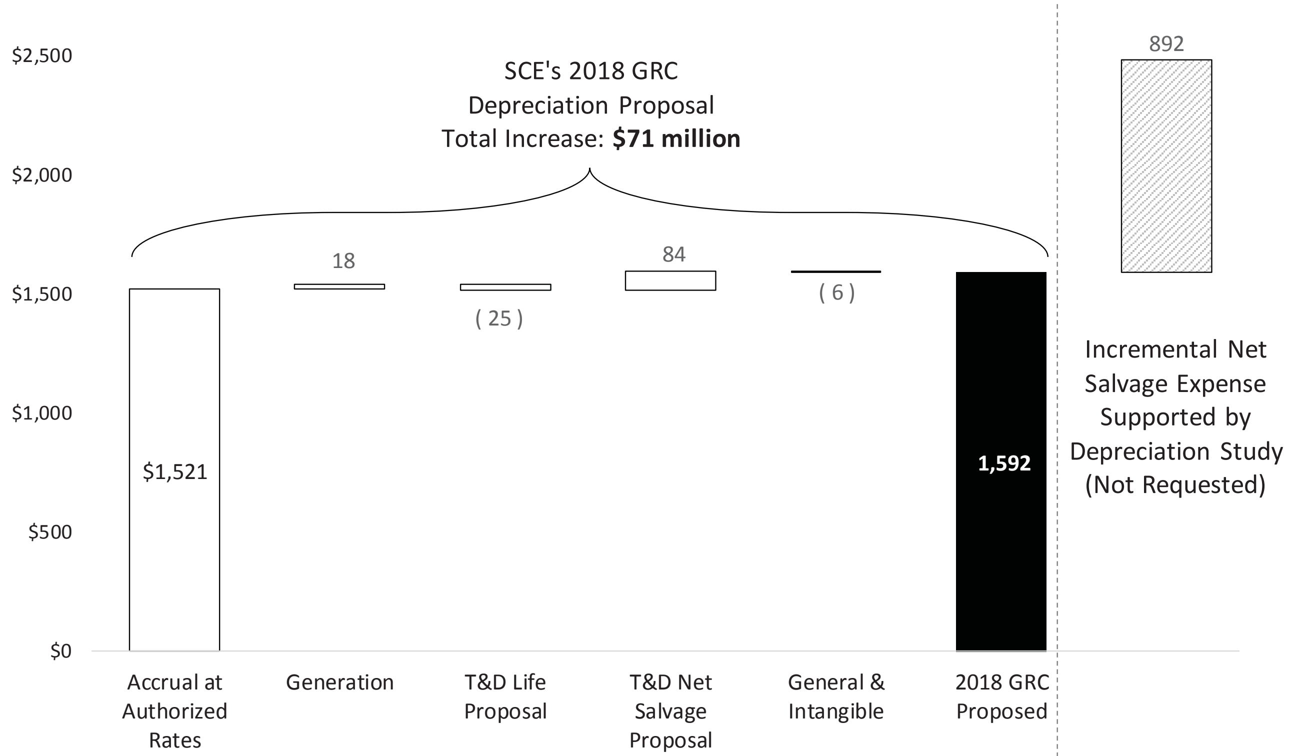
***Table I-1*[2]**
Depreciation Expense Proposal

Line No.	Item	Depreciation Expense (Nominal $M)	% Change from 2015 Recorded (Line 1)
1.	Recorded 2015 Depreciation Expense at Authorized Depreciation Rates (from 2015 GRC)	$1,656	
2.	Change due to 2016-2018 Plant Growth at Authorized Depreciation Rates	$266	*16.1%*
3a.	Change due to proposed Depreciation Rates applied to Year-End 2015 Recorded Plant	*$71*	*4.3%*
3b.	Change due to Proposed Depreciation Rates applied to 2018 Forecast Plant	*$10*	*0.6%*
3.	Total Change due to Depreciation Study (Sum of 3a and 3b)	**$81**	***4.9%***
4.	Proposed Test Year 2018 Depreciation Expense (Sum of Lines 1,2, and 3)	$2,003	*21.0%*

SCE's depreciation rate proposals (Line 3a above) can be separated into major functional categories as shown in Figure I-1 below.

2 Refer to WP SCE-09 Vol. 03, Book A, pp. 1-20 (Depreciation Rate Proposals).

Figure I-1 [3]
Impact of Proposed Depreciation Rates by Class of Plant
(Based on Year-End 2015 CPUC-Jurisdictional Plant Balances, $M)



Note: The far left bar in the figure above shows a different number ($1,521M) from Table I-1 ($1,656) for two reasons: (1) It is calculated using only year-end 2015 plant balance instead of the full year 2015 recorded plant balances; and (2) it represents CPUC-jurisdictional depreciation expense only.

The increase in generation accruals is due primarily to shorter life proposals for hydro and solar facilities (See Section B of Chapter III). For T&D, SCE proposes to extend or retain average service lives for 18 of 20 accounts, and proposes more negative NSRs for 13 of 20 T&D accounts. The small change in General & Intangible accruals is the result of SCE's proposal to recover recorded reserve deficits.

As shown in Figure I-1 above, the results of SCE's net salvage analysis support a total increase in the annual accruals for net salvage of $976 million (assuming 2.72% inflation) consisting of SCE's requested $84 million plus an additional $892 million not requested in this rate case. Section C below

[3] Because this figure is based on CPUC-jurisdictional plant balances as of Year-End 2015, it does not include the impact of forecast plant additions from 2016-2018. The estimated impact of these forecast additions is shown in Line 2 of Table I-1 above.

discusses SCE's approach to moderating its T&D net salvage expense proposals to the requested $84 million.

C. Application of Gradualism Principle to SCE's Proposal

The results of the more rigorous per-unit net salvage analysis required as part of the Commission's directives from the 2015 GRC (see Chapter II), together with a forecast of the timing of retirements,[4] supports increasing SCE's annual accruals for T&D net salvage by $976 million above currently authorized levels. This depreciation proposal "as is" would translate into a large revenue requirement increase if the Commission were to adopt it. Given the magnitude of the impact this proposal would have on retail rates, SCE requests only $84 million for T&D net salvage accruals.

SCE chooses to "temper" its depreciation request in light of the Commission's recognition that while a utility could substantiate large depreciation expense requests through "empirical analysis of cost trends,"[5] more moderated rates may be in the public interest for reasons unrelated to empirical analyses. The Commission discussed this principle—known as "gradualism"—relatively recently in its Decision Authorizing Pacific Gas and Electric Company's (PG&E's) General Rate Case Revenue Requirement for 2014-2016, D.14-08-032, where it approved increased negative net salvage rates relative to PG&E's then-current rates "but at a reduced level relative to PG&E's forecasts to mitigate ratepayer impacts and to reflect the principle of gradualism."[6]

Specifically, the Commission concluded that for all asset accounts in which net salvage amounts were contested, it would adopt no more than 25% of the estimated net increase from current rates that would otherwise result from applying PG&E's net negative salvage rates (*e.g.*, if the previously approved NSR was -50% and PG&E requested -100%, the Commission adopted an NSR no more negative than -62.5%). The Commission concluded that 25% of the difference between then-current rates and proposed rates "gives some credence to the empirical methods used by PG&E while declining

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[4] To estimate the timing of retirements, SCE used the average retirement life and dispersion curves determined through its actuarial analyses, and then applied a 2.72% capital escalation assumption to determine forecast net salvage. For an explanation about the basis of the inflation assumption, refer to WP SCE-09 Vol. 03, Book A, p. 24 (Capital Escalation).

[5] D.14-08-032, p. 596.

[6] *Id*., p. 11.

to pass along the full amount of PG&E's forecasted increase in negative salvage rates to current ratepayers."[7]

SCE's gradualism proposal in this proceeding uses a different formula than the one the Commission applied in PG&E's 2014 GRC Decision because SCE proposes to cap increases at 25% more than currently authorized NSRs rather than proposing an increase equal to 25% of the difference between proposed and authorized NSRs.[8] See Table I-2, below, for a summary of SCE's capping proposal (which was applied only to the accounts with gray highlights given that the study results would have increased the NSRs by more than 25% from authorized rates).

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[7] *Id.*, p. 602. In SCE's 2015 GRC, the Commission relied on its rationale from the PG&E case, stating that "[c]onsistent with the logic of gradualism that we applied to PG&E," it adopted a negative net salvage rate for Account 364 of -210% instead of the -225% that SCE had requested. D.15-11-021, p. 421. Similarly, for Account 369, SCE proposed an increase from -85% to -125%. "Consistent with gradualism," and for other reasons, the Commission adopted an increase to -100%. *Id.*, p. 425. In SCE's 2009 GRC, the Commission did not refer to "gradualism" as a doctrine but nonetheless tempered SCE's otherwise reasonable removal cost estimates "because of economic difficulties facing ratepayers." D.14-08-032, p. 599 (citing D.09-03-025, pp. 179-180).

[8] SCE's proposal, using the same calculation method as the Commission applied in the 2014 PG&E Decision, is equal to roughly 10% of the difference between currently authorized NSRs T&D accounts and what SCE's study results would justify.

Table I-2
SCE's Proposed Net Salvage Ratios for T&D Accounts

FERC Acct	Description	2015 GRC Authorized	Study Results	25% Above Authorized	SCE's NSR Proposals
A	B	C	D	E=C*1.25	G=Lesser of D or E
Transmission Plant					
352	Structures and Improvements	35%	35%	44%	35%
353	Station Equipment	15%	10%	19%	10%
354*	Towers and Fixtures	60%	185%	75%	75%
355*	Poles and Fixtures	72%	499%	90%	90%
356*	Overhead Conductors and Devices	80%	210%	100%	100%
357	Underground Conduit	0%	0%	0%	0%
358	Underground Conductor and Devices	15%	25%	19%	19%
359	Roads and Trails	0%	0%	0%	0%
Distribution Plant					
361	Structures and Improvements	25%	30%	31%	30%
362	Station Equipment	25%	50%	31%	31%
364*	Poles, Towers and Fixtures	210%	488%	263%	263%
365*	Overhead Conductors and Devices	115%	538%	144%	144%
366*	Underground Conduit	30%	401%	38%	38%
367*	Underground Conductor and Devices	60%	261%	75%	75%
368*	Line Transformers	20%	47%	25%	25%
369*	Services	100%	387%	125%	125%
370	Meters	5%	0%	6%	0%
373	Streetlights	30%	100%	38%	38%

* *Used a per-unit analysis to arrive at proposed net salvage rates*

The moderated NSRs, taken together with the balance of SCE's depreciation proposal, result in a total depreciation request that is less than 5 percent above what the Commission authorized for SCE in the 2015 GRC Decision.

SCE has weighed the balance between setting rates in this GRC based on cost-of-service principles, on the one hand, and being mindful of customer rate impacts, on the other. SCE also acknowledges errors inherent in any forecast of lives and removal costs of long-lived assets given the many variables that will eventually bear on the final costs. SCE recognizes the Commission's statement that one must "be cautious in making large changes in estimates of service lives and net salvage for property that will be in service for many decades, as future experience may show the current estimates to be incorrect."[9] Indeed, the premise of SCE's per-unit analysis is that one can take the per-unit historical

[9] D.14-08-032, p. 598.

cost to remove assets, and apply that per-unit cost to the *quantities* of assets in the surviving plant balance to obtain a reasonable forecast of the cost to remove the assets given projections about the timing of the assets' retirements. A key assumption in this analysis is the per-unit cost to retire each asset. While the proposals presented in SCE's depreciation study substantiate sound estimates of the future costs to retire, SCE does not overlook that future rate cases will provide updates to SCE's recorded experience that will further refine the expectations of future net salvage. That is, in future rate cases, SCE will have the ability to take its then-surviving plant balances to even better refine its projections about the future in light of then-available conclusions about historical costs-per-unit. By moderating SCE's depreciation expense, the Commission will make progress towards SCE's current estimate of forecast net salvage while permitting the Company in future rate cases to rely on additional data to refine its forecasts.

D. Summary Tables

Table I-3, Table I-4, and Table I-5 below summarize the life and net salvage parameters resulting from the analyses described in the chapters below.

Table I-3[10]
Summary of SCE's Request for Depreciation Parameters - Transmission and Distribution

FERC Account	Description	Net Salvage Rates			Curves and Lives			Depreciation Rates		
		Auth.	Prop.	Change	Auth.	Prop.	Change	Auth.	Prop.	Change
A	B	C	D	E=D-C	F	G	H=G-F	I	J	K=J-I
Transmission										
352	Structures and Improvements	-35%	-35%		S 3.0 55	L 1.0 55		2.53%	2.40%	*-0.13%*
353	Station Equipment	-15%	-10%	*5%*	R 0.5 45	L 0.5 40	*-5*	2.66%	2.84%	*0.18%*
354	Towers and Fixtures	-60%	-75%	*-15%*	R 5.0 65	R 5.0 65		2.30%	2.73%	*0.43%*
355	Poles and Fixtures	-72%	-90%	*-18%*	R 0.5 50	SC 65	*15*	3.43%	2.84%	*-0.59%*
356	Overhead Conductors & Devices	-80%	-100%	*-20%*	R 3.0 61	R 3.0 61		2.63%	3.24%	*0.61%*
357	Underground Conduit	0%	0%		R 3.0 55	R 3.0 55		1.73%	1.73%	*0.00%*
358	Underground Conductors & Devices	-15%	-19%	*-4%*	R 2.5 40	S 1.0 45	*5*	2.65%	2.41%	*-0.24%*
359	Roads and Trails	0%	0%		SQ 60	R 5.0 60		1.52%	1.65%	*0.13%*
Distribution										
361	Structures and Improvements	-25%	-30%	*-5%*	R 2.5 42	L 0.5 50	*8*	3.04%	2.39%	*-0.65%*
362	Station Equipment	-25%	-31%	*-6%*	R 1.5 45	L 0.5 65	*20*	3.13%	2.01%	*-1.12%*
364	Poles, Towers and Fixtures	-210%	-263%	*-53%*	L 0.5 47	R 1.0 55	*8*	7.04%	7.09%	*0.05%*
365	Overhead Conductors & Devices	-115%	-144%	*-29%*	R 0.5 45	R 0.5 55	*10*	4.87%	4.49%	*-0.38%*
366	Underground Conduit	-30%	-38%	*-8%*	R 3.0 59	R 3.0 59		2.22%	2.27%	*0.05%*
367	Underground Conductors & Devices	-60%	-75%	*-15%*	R 0.5 45	R 1.5 43	*-2*	2.98%	3.94%	*0.96%*
368	Line Transformers	-20%	-25%	*-5%*	R 1.0 33	S 1.5 33		3.93%	4.57%	*0.64%*
369	Services	-100%	-125%	*-25%*	R 1.5 45	R 1.5 45		4.34%	5.04%	*0.70%*
370	Meters	-5%	0%	*5%*	R 3.0 20	R 3.0 20		5.30%	5.61%	*0.31%*
373	Street Lighting & Signal Systems	-30%	-38%	*-8%*	L 0.5 40	L 1.0 48	*8*	3.10%	3.00%	*-0.10%*
General Buildings										
390	Structures & Improvements	-10%	-10%	*0%*	R 3.0 38	R 0.5 45	*7*	2.74%	2.08%	*-0.66%*

Used a Per-Unit Analysis to analyze Net Salvage

Moderated as discussed in Chapter 1, Section C

Proposed Retention of Currently Authorized Lives

10 Refer to WP SCE-09 Vol. 03, Book A, pp. 5-20 (Rate Determination Schedule).

Table I-4[11]
Summary of SCE's Request for Book Depreciation
Generation Plant

Generation Facility	Life Spans		Net Salvage	
	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	30.5 yrs.	28.0 yrs.	Covered under NDCTP	
Hydro Production	26.0 yrs.	19.9 yrs.	$79.3 M	$95.3 M
Other Production				
Pebbly Beach	45 yrs.	25 yrs.	$6.6 M	-
Mountainview	35 yrs.	35 yrs.	$16.3 M	$18.5 M
Peakers	35 yrs.	35 yrs.	$12.1 M	$15.1 M
Solar Photovoltaic	25 yrs.	20 yrs.	$81.9 M	$80.9 M
Fuel Cells	10 yrs.	10 yrs.	-	-
Energy Storage	N/A	10 yrs.	N/A	-

Table I-5[12]
Summary of SCE's Request for Book Depreciation
General and Intangible Plant

FERC Account	Description	Lives		Depreciation Rates	
		Auth.	Prop.	Auth.	Prop.
A	B	C	D	E	F
General Plant					
389.2	Easements	60	60	1.67%	1.67%
391.1	Office Furniture	20	20	5.00%	5.00%
391.2	Personal Computers	5	5	20.00%	20.00%
391.3	Mainframe Computers	5	5	20.00%	20.00%
391.4	DDSMS-Security Monitoring System	Various	Various	12.90%	9.84%
391.5	Office Equipment	5	5	20.00%	20.00%
391.6	Duplicating Equipment	5	5	20.00%	20.00%
391.7	PC Software	5	5	20.00%	20.00%
393	Stores Equipment	20	20	5.00%	5.00%
394	Tools & Work Equipment	10	10	10.00%	10.00%
395	Laboratory Equipment	15	15	6.67%	6.67%
397	Telecommunication Equipment	Various	Various	9.77%	11.65%
398	Misc. Power Plant Equipment	20	20	5.00%	5.00%
Intangible Plant					
302.020	Hydro Relicensing	Various	Various	2.52%	2.47%
303.640	Radio Frequency	40	40	2.50%	2.50%
302.050	Miscellaneous Intangibles	20	20	5.00%	5.00%
303.105	Capitalized Software - 5 year	5	5	20.00%	20.00%
303.707	Capitalized Software - 7 year	7	7	14.29%	14.29%
303.210	Capitalized Software - 10 year	10	10	10.00%	10.00%
303.315	Capitalized Software - 15 year	15	15	6.67%	6.67%

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[11] *Id.*, pp. 5-7.
[12] *Id.,* pp. 9-12.

II.

COMMISSION DIRECTIVES FROM SCE'S 2015 GRC DECISION

In the 2015 GRC Decision, the Commission gave four directives for SCE's net salvage proposals in this 2018 GRC proceeding. Most of the remainder of this chapter explains SCE's approach to meeting each of the directives. Section D addresses SCE's experience with increasingly negative net salvage rates (this testimony refers to "higher" net salvage rates, for simplicity's sake) and demonstrates how the advancing age of SCE's infrastructure and the increasing urbanization within its service territory has contributed to more negative NSRs.

A. The Four Directives Established in the 2015 GRC Decision

Ordering Paragraph 9 of the 2015 GRC Decision required SCE to "provide considerably more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense" including at least the following:[13]

The First Directive

> "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per-unit COR."

The Second Directive

> "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."

The Third Directive

> "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross-reference the proposal for life characteristics."

The Fourth Directive

> "An account-specific discussion of the process for allocating costs to COR."[14]

The per-unit analysis required by the Commission involves substantially more work than a "traditional" net salvage analysis that is typically performed by the industry (as described in Standard Practice U-4).[15]

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[13] D.15-11-021, Ordering Paragraph 9, p. 554.

[14] *Id*., pp. 554-555.

[15] For the purpose of this testimony, the term "traditional approach" will be used to describe Standard U-4.

Table II-6, below, summarizes the differences at a high level, and Sections B and C of this chapter goes into more detail.

Table II-6
Summary of Difference Between Per-Unit Analysis and Traditional Approach

	Compliance Directive from 2015 GRC	Per-Unit Analysis (Required by 2015 GRC Decision)	Traditional Approach (As Established in Standard Practice U-4)
1.	**Perform a per-unit COR analysis**	Separate account into sub-populations (*e.g*., account 365 conductor vs. account 365 switches) and calculate a per-unit COR. Math: Historical cost to retire assets divided by *quantities* of property units being retired within each subpopulation.	Calculate NSR at the account level of detail (e.g., account 365). Math: Historical cost to retire assets divided by *original cost* of assets retiring.
2.	**Discuss Whether Retirement Mix Will Change Or Stay The Same**	Apply the per-unit cost estimate results to surviving plant balance assuming that the future retirement mix will be consistent with the current plant balance.	Assumes that the future retirement mix will mimic SCE's recorded experience.
3.	**Integrate Salvage Analysis with Life Analysis**	Utilize original cost of current plant-in-service and results of the life analysis to estimate timing and cost of future retirements.	Assume that the future average age of retirements, and the inflation embedded in the cost of removal, will both mimic recorded activity.
4.	**Discuss COR Allocation**	Provide account-specific discussion for the process for assigning costs to cost of removal (versus install).	

B. <u>SCE's Approach to Addressing the Compliance Directives from the 2015 GRC Decision</u>

To comply with the directives from the 2015 GRC Decision, SCE performed a per-unit analysis for "at least five of the largest accounts, as measured by [the] proposed annual depreciation expense." As shown in Table II-7, below, the five largest accounts under that definition are distribution accounts 364, 365, 367, 368, and 369.[16]

SCE performed a per-unit analysis on nine T&D accounts, which comprise 85% of the total COR expense proposed. Apart from the five largest accounts, SCE performed a per-unit analysis on another distribution line account, Account 366, which is the only remaining account in the series 364-369 (covering distribution line circuits). In addition, SCE performed a per-unit analysis for Account 354 (Transmission Towers) because a traditional analysis produced anomalous estimates of future net salvage rates (upwards of -800%) resulting from the removal of very old towers with a high cost to retire. SCE also selected accounts 355, 356, and 366 (Transmission Poles, Transmission Overhead

16 The same five T&D accounts represented the top five accounts (measured by proposed depreciation expense) in the 2015 GRC.

Conductor, and Distribution Underground Conduit respectively) given their similarity to corresponding distribution account assets for which SCE conducted a per-unit analysis.

The Commission's directives from the 2015 GRC Decision stand alone. However, in the course of complying with those directives, SCE is indirectly addressing related directives from SCE's 2012 GRC Decision (D.12-11-051, pp. 683-686). In the 2012 GRC decision, the Commission asked SCE to: (1) provide more information about its cost of removal estimates; and (2) to "review its allocation practices to be sure that all installation-related costs are booked to Plant-in-Service," instead of to cost of removal.[17] Both decisions request additional information substantiating removal costs and reviewing SCE's cost allocation. The primary distinction is that the 2015 GRC Decision required SCE to analyze its largest accounts by the proposed depreciation expense, whereas the 2012 GRC Decision instead required that SCE select its largest accounts using industry comparisons.

[17] D.12-11-051, p. 683.

Table II-7
T&D Accounts Ranked by Proposed Annual Depreciation Expense
(Based on CPUC-Jurisdictional Depreciation Expense ($M))

FERC Account	Description	Proposed Depr. Exp.	Rank
Transmission Plant			
352	Structures and Improvements	5,101	*15*
353	Station Equipment	62,978	*6*
354	Towers and Fixtures	2,603	*16*
355	Poles and Fixtures	19,820	*11*
356	Overhead Conductors & Devices	7,856	*13*
357	Underground Conduit	1,053	*17*
358	Underground Conductors & Devices	6,160	*14*
359	Roads and Trails	114	*18*
Distribution Plant			
361	Structures and Improvements	13,783	*12*
362	Station Equipment	45,110	*8*
364	Poles, Towers and Fixtures	174,654	***2***
365	Overhead Conductors & Devices	64,341	***5***
366	Underground Conduit	44,209	*9*
367	Underground Conductors & Devices	218,724	***1***
368	Line Transformers	160,345	***3***
369	Services	65,591	***4***
370	Meters	50,205	*7*
373	Streetlights	26,163	*10*
Total		968,810	

Proposals based on results of Per-Unit Analysis ($758M or 78% of Total Expense)

1. The First Directive – Per Unit Net Salvage Analysis

The per-unit net salvage analysis segments each FERC plant account into large subpopulations (*i.e.*, dollar value of assets representing more than 15% of the total account balance).[18] To calculate the average per-unit cost to remove, SCE divided the net salvage dollars incurred by the quantity of units retired for each of the identified subpopulations. For example, Account 368—

[18] In the first compliance directive from the 2015 GRC Decision, the Commission referred to "large . . . asset classes in the account" as measured by 15% or more of the portion of plant balance. D.15-11-021, p. 398. SCE uses the term "subpopulation" to refer to those large asset classes within each FERC account.

Distribution Line Transformers—consists of three major subpopulations; overhead (OH) transformers, underground (UG) transformers, and fuseholders. For each subpopulation, SCE divided the net salvage incurred from 2009-2015[19] by the quantity of units retired, as shown in Figure II-3, below. This per-unit cost to remove each asset formed one part of the basis for forecasting SCE's expected future net salvage proposals presented in this GRC.

a) Traditional Approaches to Analyzing Historical and Future Net Salvage

Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals ("U-4," or "Standard Practice U-4"), "sets forth various factors influencing the determination of depreciation accruals and describes methods of calculating these accruals"[20] with the purpose of assisting "the Commission staff in determining proper depreciation expenses."[21] Although over 50 years old, Standard Practice U-4 represents conventional utility depreciation practices. The depreciation rates proposed in this study are consistent with the standard practices described in U-4. In addition, SCE conducted a more rigorous per-unit analysis for nine T&D accounts in response to the Commission's directives from the 2015 GRC.

To meet requirements set forth in U-4, SCE uses different approaches to estimate NSRs based on the plant's retirement characteristics and recorded experience. Broadly speaking, SCE's net salvage study analyzes mass property differently than life-span property and other non-mass plant accounts. Mass property accounts (*e.g.,* transmission and distribution plant accounts) are those that have a significant number of property units which are generally retired separately. Life-span property refers to accounts which are comprised of a few major units which individually are expected to retire at a single point in time (*e.g.*, generating plants).

Mass property plant accounts, such as T&D, can contain a significant number of components and generally experience large numbers of retirement transactions under a diverse number of retirement circumstances. The large number of retirement units and retirement occurrences for mass property generally necessitate an analysis of *aggregate* historical NSRs and per-unit costs. To accomplish this, Standard Practice U-4 describes how to estimate future net salvage rates using the

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19 This period contains detailed net salvage data by CPR, available in PowerPlan, SCE's capital system of record. Net salvage data prior to this period is maintained at the FERC prime account level only.

20 Standard Practice U-4 is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M042/K177/42177433.PDF and includes methods to analyze net salvage.

21 *Id.*, p. 6.

experienced ratios of net salvage, gross salvage, and removal cost (in today's dollars) as a percent of the original installed costs (in older dollars) of retirements. The average net salvage rate by FERC account is then applied to the total plant balance to determine the estimated future net salvage amount, barring any adjustments. Understanding the inputs involved in the calculation and the calculation itself is important to interpreting the resulting NSRs. The calculations are as follows:

Figure II-2
Computing NSRs Under the Traditional Approach

$$\text{Net Salvage \%} = \text{Gross Salvage \%} - \text{Removal Cost \%}$$

$$\frac{\text{Net Salvage (\$)}}{\text{Retirements (\$)}} = \frac{\text{Gross Salvage (\$)}}{\text{Retirements (\$)}} - \frac{\text{Removal Cost (\$)}}{\text{Retirements (\$)}}$$

b) <u>Comparing the Differences Between Calculating Net Salvage Ratios Using a Traditional Analysis Versus Per-Unit Analysis</u>

The first and most important way that a per-unit analysis differs from the traditional analysis is that the NSRs are computed using the original cost of the *surviving* plant balance (*i.e.*, the current plant balance), as opposed to a traditional analysis' use of the original cost of the plant that has already *retired*. That is, a traditional net salvage analysis examines the *historical* NSRs as the principal factor used to estimate *future* NSRs. By contrast, the per-unit analysis takes historical per unit costs and applies them to surviving plant *quantities* to project future removal costs given projections (from the life analysis) of when assets are expected to retire. The traditional approach implicitly assumes that factors such as the age of retirements, changes in SCE's operating environment, levels of inflation and other factors will, in the future, be the same as they were in the past. By contrast, a per-unit analysis develops forward-looking estimates of net salvage by relying on recorded costs, surviving plant balances, and assumptions about the timing of future retirements.

An illustration of SCE's approach to the per-unit analysis computation is instructive, especially compared to the calculation in Figure II-2, above. First, the net salvage cost per-unit is calculated by summing seven years' worth of recorded history—in both dollars used to remove assets, and quantities of assets removed—to arrive at a per-unit net salvage value by sub-population:

Figure II-3
Calculation of Per-Unit Net Salvage Costs
(Recorded 2009-2015 values for Account 368 – Line Transformers)

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage (\$)}}{\text{Quantity Retired}}$$

		Overhead Transformer	Underground Transformer	Fuseholder	Others
Per-Unit Net Salvage	=	$79,500,742 / 141,838	$78,642,058 / 53,904	$44,409,667 / 275,472	$19,071,340 / 19,862
	=	$560.50	$1,458.93	$161.21	$960.19

Next, the per-unit cost derived above is applied to a forecast using anticipated rates of inflation, as opposed to inflation experienced in the past. A simplified (no-inflation) calculation of future net salvage is shown in Figure II-4, as it shows the per-unit net salvage from Figure II-3 multiplied by the year-end 2015 surviving quantities (the study date). The resulting value is equivalent to an estimate of the cost to remove all of the assets in Account 368 as of the study date.

Figure II-4 [22]
Calculation of Future Net Salvage Using a Per-Unit Methodology
(for Account 368 – Line Transformers; excluding future inflation)

$$\text{Future Net Salvage} = \text{Per-Unit NS} \times \text{Per-Unit Surviving Quantity}$$

		Overhead Transformer		Underground Transformer		Fuseholder		Others
Future Net Salvage	=	$560.50 x 456,611	+	$1,458.93 x 259,299	+	$161.21 x 1,400,640	+	$960.19 x 62,788
$920,320,858	=	$255,932,428		$378,298,499		$225,801,375		$60,288,556

This forecast of future net salvage can be divided by the costs of assets currently serving customers (the denominator, or surviving plant balance) to arrive at an estimated future NSR. This no-inflation estimate of the future NSR is shown in Figure II-5 below.

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22 Refer to WP SCE-09 Vol. 03, Book A, pp. 21-24 (Per-Unit Calculations).

Figure II-5[23]
Derivation of Future Net Salvage Rate Under a Per-Unit Analysis
(for Account 368 – Line Transformers; excluding future inflation)

$$\text{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}}$$

$$\mathbf{\mathit{26.7\%}} = \frac{\$920,320,858}{\$3,450,870,284}$$

To summarize, a per-unit analysis estimates future net salvage by: 1) establishing a per-unit cost to retire each asset, 2) applying results of the life analysis to estimate when these costs will be incurred, and 3) dividing this forecast net salvage by the surviving plant balance. See Figure II-6 below for a simplified comparison of the differences.

Figure II-6
Simplified Comparison of Traditional Analysis vs. Per-Unit Analysis

Traditional Analysis

$$\textbf{Future Net Salvage Rate} = \frac{\text{Net Salvage Incurred}}{\textit{Cost}\ \text{Retired}}$$

Per-Unit Analysis

$$\text{Per-Unit Net Salvage} = \frac{\text{Net Salvage Incurred}}{\textit{Quantity}\ \text{Retired}}$$

$$\text{Future Net Salvage} = \text{Per-Unit Net Salvage} \times \text{Surviving Quantity}^{1}$$

$$\textbf{Future Net Salvage Rate} = \frac{\text{Future Net Salvage}}{\text{Surviving Plant}^{2}}$$

1. Multiplying by surviving quantity produces forward-looking estimates of net salvage (in more complex examples, the timing of removal and level of inflation will change the per unit net salvage value).
2. Using the surviving plant balance is representative of the future retirement mix.

2. The Second Directive – Retirement Mix

The second directive, requiring a discussion of the historical and future retirement mix, has been addressed by separating the original directive into two sub-directives (1) an analysis and

23 *Id*.

discussion of the historical retirements, and (2) a discussion of the expected future retirement mix. The per-unit analysis described above complies with the first sub-directive because it requires review of the historical mix of retirements to determine an average per-unit cost to retire. To address the second sub-directive, SCE assumes that the future retirement mix will be consistent with the asset mix in the surviving plant balance as of year-end 2015. (In future rate cases, when the retirement mix changes, the forecast NSR will change accordingly.)

Analyzing the account by subpopulation achieves a more detailed “weighting” than looking at the account-based retirement mix in the aggregate. That is, the traditional approach focuses solely on the backward-looking ratios, which are used to estimate *future* net salvage. The blunt assumption underlying this approach is that the mixture of asset retirements in the past is representative of what one could expect in the future without regard to the composition of the then-current plant balance. Under the per-unit approach, by contrast, one focus is on the *surviving* plant balance, which offers a “snapshot” in real time that forms the basis for estimating the future mix of retirements. In determining its proposed depreciation expense, SCE did not identify or rely on factors that would cause it to modify the future retirement mix relative to the mix that currently exists in its plant accounts. Should factors in the future modify the retirement mix, the surviving plant balances examined at the relevant time will integrate and reflect those changes.

3. The Third Directive – The Age of Retirements and Integration of Salvage and Life Analyses

The third directive requires SCE to provide a quantitative discussion of the life of assets and original cost of assets being retired in relation to the cost of removal. This directive has been addressed by separating the original directive into two sub-directives requiring (1) a discussion of the age of retirements *experienced* and (2) a forecast of the *future* age of retirements given the results of the life analysis. The Commission intended this directive to “integrate” the life analysis with the COR analysis: “This [COR] discussion should be integrated with and/or cross-reference the proposal for life characteristics.”[24] The only way to properly integrate both prongs of the analysis is to factor in the impact of the *passage of time*, or inflation, on the per-unit costs. To address this directive, SCE has provided the average age and original cost of assets retired, together with a forecast of future retirements

[24] D.15-11-021, p. 398 (see also Ordering Paragraph 9.i., pp. 554-555).

using the results of the life analysis. SCE's forecasts are derived by integrating the historical (per-unit) cost to remove each asset with the forecast retirements from the life analysis.

4. The Fourth Directive – Process for Assigning Costs

In compliance with the fourth directive from the 2015 GRC Decision—requiring SCE to provide an "account-specific discussion of the process for allocating costs to COR" for at least five of the largest accounts[25] — Section C below describes in detail SCE's process for allocating a portion of total work order costs to cost of removal.

C. Process for Assigning Costs to Installation and Removal (The Fourth Directive)

The 2015 GRC Decision requested an "account-specific" discussion of the process for allocating costs to removal. For every capital project SCE undertakes, one or more work orders is created and populated with a Unit Estimate (UE) in PowerPlan, which is SCE's fixed asset accounting software system. UEs are comprised of *property* descriptions, otherwise known as continuous property records (CPRs), and *activity* descriptions. An example of a CPR is 364.330 for a distribution wood pole the "364" refers to FERC plant account 364 Distribution Poles, and the ".330" suffix refers to an SCE-specific retirement unit, in this case, a solely-owned wood pole.

The activity description of a UE is used to denote whether the activity undertaken within each work order involves: Installation of a new asset, Removal of an existing asset, or related Expense (I/R/E).[26] For each project, SCE personnel will populate a UE with the CPR and activity types that are specific to the project that they are estimating. (Note that capital material costs are assigned to Install, whereas, labor costs are assigned to I/R/E.)

UEs originate from two different "categories" of capital projects, each of which broadly uses a different cost assignment methodology. The first category is relevant to bulk-power transmission, substation, and generation-related projects, which combined account for approximately 15% of SCE's total 2016-2020 forecast cost of removal in this rate case. In general, the assets in this category are booked to all plant accounts other than Accounts 364-373, and the process for allocating costs is described in subsection II.C.1, "Project-Specific Estimating" below.

The second category is relevant to distribution and sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), which together account for the majority (approximately 85%) of SCE's

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[25] *Id.*

[26] For this cost assignment description, the "expense" category is considered a non-capitalized activity but is included here for completeness.

total 2016-2020 forecast COR in this rate case. At a high level, the assets in this second category (sometimes referred to as "mass plant" assets) are booked to Accounts 364 to 373, and the process for assigning costs is described in subsection II.C.2., "Design Manager (DM) Estimating" below.

1. Project-Specific Estimating (Bulk-Power Transmission, Substation, and Generation/Other)

For project-specific estimating, SCE personnel create a detailed cost estimate for each of the activities required at the outset of each job. The cost estimate reflects the total estimated costs of *installation* separate from the total estimated costs of *removal*.

a) Bulk Power Transmission and Substation (Accounts 350-359 and 362)

For bulk power transmission and substation estimates,[27] engineers and technical experts use the Scope and Cost Management Tool (SCMT) to document, track, and communicate the scope for each project. Cost estimators then complete the costs for each project identifying and separating the installation, removal and expense activities. They assign CPR accounts that serve as the basis for creating the UEs that will ultimately be uploaded into the PowerPlan system.

For example, a capital project to replace a bulk power (*e.g.*, 500/220 kV) transformer begins when the estimator develops a specific cost estimate by itemizing the scope of major activities (*e.g.*, removing the old transformer, trench cover, power/control cable, conduits, etc. and then installing the new equipment).[28] The installation and removal activities are separately identified by hours required to install and/or remove the particular assets. In other words, there is a specific estimate of the labor, equipment, and associated overheads required to remove assets, and it is not a template-based "allocation" of *total* hours required for the job. The work is also broken out by the specific classification of employee who will be performing the task and also whether or not SCE crews or contract crews will be performing the work. The details of this estimate are compiled and used to create the UE in PowerPlan that will assign the ultimate costs recorded as "installation" costs versus "removal" costs.

b) Generation and Other (Accounts 301-348, and 390-398) [29]

Generation, Information Technology, and Operational Services also use project-specific estimating. That is, a detailed scope of work is set by engineers and other technical experts. The

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[27] Examples of accounts with related assets are Accounts 350 to 359 and 362.
[28] Refer to WP SCE-09 Vol. 03, Book A, pp. 25-41 (Project-Specific Estimating) for an example of a project-specific estimate.
[29] Examples of some of these accounts are: Accounts 301 to 348 and 390 to 398.

scope of work is separated into installation and removal activities and becomes the foundation for building the UEs that are put in the PowerPlan System.

2. Design Manager (DM) Estimating (Distribution/Sub-Transmission Assets)

For the large majority of capital assets, such as distribution and some sub-transmission line assets (*e.g.*, poles, conductors, streetlights, etc.), it is impractical for SCE to use project-specific estimating every time a new capital project is undertaken. That is because in any given year, SCE will install and replace thousands of these units of property. For example, in 2015 alone, SCE replaced over 40,000 wood poles, 25,000 transformers, and 3,000 miles of conductor.[30]

To manage the high volume of work, SCE uses a template-based estimating approach to assign a capital project's total costs to Installation, Removal, and Related Expense (I/R/E). Since 2010, SCE's planners have been using Design Manager to estimate labor hours, schedule work, and price distribution and sub-transmission projects. The DM estimating approach is commonly used for emergency work, planned/routine work, and customer-driven projects including relocations, overhead/underground conversions, new service connections and meter installations. A subset of data from DM is sent to PowerPlan, and that is where SCE's allocation methodology is applied for fixed asset accounting purposes, as explained in more detail below.

a) Building a Project Estimate in DM Using Compatible Units (CUs)

A planner tasked with initiating a project (*e.g.*, a pole replacement) will open a work order and, based on the project scope (including site visits, where applicable), begin identifying Compatible Units (CUs) required to complete the job. CUs are building blocks of material and labor used to develop the distribution design and work order cost estimates. They eliminate the need for planners to manually identify and select every material component for frequently installed equipment and structures on SCE's electrical system. CUs identify the quantity and type of property needed for a project (*e.g.*, wood poles, transformers, conductors, etc.) and associated estimates of labor hours and costs. DM contains legend codes to indicate the type of activity to be performed for each asset (*i.e.*, installation vs. removal). DM incorporates the use of over 4,500 distribution CUs, to help planners build cost estimates and schedule work depending on the requirements of the job.

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[30] Refer to WP SCE-09 Vol. 03, Book D, pp. 2-40 (Per-Unit Net Salvage Analysis). Estimates are taken from per-unit analysis quantity.

b) Cost Allocation in PowerPlan

For purposes of fixed asset accounting, the CUs and legend codes from DM work orders are migrated to PowerPlan. CUs are paired with—and converted to—one of over 100 CPR accounts.[31] At this point, the CPR account consists only of quantities and types of property to be installed and, if applicable, quantities and types of property to be removed. The estimated costs and labor hours from DM are not carried over to PowerPlan. For fixed asset accounting purposes, SCE uses a "Standard Rates Table"[32] to allocate installation and removal costs relative to total project costs of individual work orders. The Standard Rates Table is also used to allocate costs among the appropriate FERC accounts.

Each CU relates to a specific, individual piece of property. For example, different CUs are used to reflect the various height, class, material, and treatment status[33] of poles. Likewise, different CUs are used to reflect the various size, voltage and even manufacturer of transformers. The number of CUs that planners use to build a UE is many times greater than the number of CPRs to which the CUs are paired in PowerPlan. The Standard Rates Table allocation is therefore performed at an aggregated level that accounts for the various types of property the CPRs encompass. The table has been in continuous use since approximately the 1970s and it sets forth allocation factors that have been studied but that have not been materially modified over the years. However, in Chapter II.C.2.c., SCE describes three studies validating that the Standard Rates Table's general allocations continue to be reasonable, if not more conservative in assigning costs to removal versus installation.

An example of how the Standard Rates Table works in PowerPlan is illustrated in the three tables below, Table II-8, Table II-9, and Table II-10. Assume that a project to replace a wood pole also requires replacing an attached streetlight fixture. The table below lists the CPRs and the associated allocation factors by activity:[34]

[31] A CPR account is defined as the combination of a FERC plant account and a retirement unit subaccount.
[32] In prior rate cases, this "Standard Rates Table" has sometimes been referred to as "Table 34."
[33] Treatment processes vary and are used to minimize pole decay (*e.g.*, through-boring, treatments, etc.).
[34] Note that the numbers are neither dollars nor hours; they are allocation factors from the Standard Rates Table. Refer to WP SCE-09 Vol. 03, Book A, pp. 47-51 (Standard Rates Table).

Table II-8
Standard Rates Table Values

CPR Account	Description	Standard Rates Table Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	1,286	+	600	=	1,886
		+		+		
373.390	Streetlight fixture	105	+	74	=	179
		=		=		
	Total	1,391	+	674	=	**2,065**

The Standard Rates Table values are not important as absolute values; they are only meaningful in relation to each other. In the example above, the value assigned to removing the pole (600) is—appropriately—much larger than the value assigned to removing the fixture (74).

Table II-9 below converts the values in the rows and columns above to percentages of the total. Comparing the values across columns shows the allocation between install and removal. Comparing the values between rows shows the allocation between CPR accounts.

Table II-9
Percent of Sum of Standard Rates

CPR Account	Description	Percent of Sum of Standard Rates Values				
		Install		Removal		Total
364.330	Distribution Wood Pole	*62%*	+	*29%*	=	*91%*
		+		+		
373.390	Streetlight fixture	*5%*	+	*4%*	=	*9%*
		=		=		
	Total	*67%*	+	*33%*	=	***100%***

Allocation between CPR Accounts

Allocation between Install and Removal for replacement project

For fixed asset accounting purposes, the percentages from the table above are applied to the allocable dollars[35] in the project's work order, as shown in Table II-10 below.

[35] Material costs are generally allocated to installation, not removal.

Table II-10
Application of Standard Rates to $1,000 of Labor

CPR Account	Description	Application of Standard Rates to $1,000 of Labor				
		Install		Removal		Total
364.330	Distribution Wood Pole	$623	+	$290	=	$913
		+		+		
373.390	Streetlight fixture	$51	+	$36	=	$87
		=		=		
	Total	$674	+	$326	=	**$1,000**

As illustrated in Table II-8, Table II-9, and Table II-10 above, while the Standard Rates Table uses a template approach to setting allocation factors, the resulting cost assignment for each project is “customized” in several ways. First, by virtue of the planner’s initial designation of CU legend codes, the *activity* for each CPR is appropriately designated as “installation” versus “removal,” and these splits are specific to each project depending on the properties and quantities that are installed or removed. Second, the *quantities* of property estimated by planners are drawn into PowerPlan and trued up by the end of every project to reflect what was actually removed and installed. Third, and most importantly, as units of property and quantities change with each work order, the matrix of cost assignment becomes more complex and reflective of the work performed in that project. For example, if another CPR account were added to the illustration above, the resulting allocations would be modified to reflect the weight of each CPR account relative to the total.

3. <u>Substantiating SCE’s Standard Rates Table Allocation Factors</u>

SCE has conducted three studies substantiating the results of the Standard Rates Table’s installation and removal allocation factors—in 2004, 2006, and 2016. The results of these three studies are summarized in Table II-11, which shows the CORs as a percentage of total costs under the Standard Rates Table compared to the COR percentages from the 2004, 2006 and 2016 Studies. The table demonstrates that SCE’s allocation practice continues to be reasonable and appropriate. In fact, the Standard Rates Table COR allocations (on which the proposals for depreciation expense are based) are the most conservative with respect to removal costs given that the study results indicate that more dollars *could* be assigned to removal using cost assignment data from field experts.

Table II-11[36]
Comparison of Cost Assignment Ratios Across Three Studies Relative to the Standard Rates Table
(Stated as Percentage of Total Cost)

FERC Account	Description	Standard Rates Table	2004 Study	2006 Study	2016 Study
Transmission Plant					
354	Towers and Fixtures		Not Applicable - Non-Mass Plant		
355	Poles and Fixtures	27.2%	30.2%	31.4%	Not Studied
356	Overhead Conductors & Devices	42.1%	56.1%	56.7%	Not Studied
Distribution Plant					
364	Poles, Towers and Fixtures	36.6%	43.0%	39.4%	46.1%
365	Overhead Conductors & Devices	34.7%	38.6%	37.1%	35.6%
366	Underground Conduit	20.0%	42.3%	41.9%	41.7%
367	Underground Conductors & Devices	34.7%	32.1%	33.7%	35.7%
368	Line Transformers	27.3%	47.4%	48.8%	41.6%
369	Services	35.5%	44.2%	44.5%	33.8%
	Weighted Average*	33.0%	38.8%	38.3%	37.5%

**Weighted by 2009-2015 Recorded Net Salvage*

a) 2004 Study [37]

In the 2004 Study, performed for the 2006 GRC, SCE assembled field operations experts who compiled and analyzed work requirements for replacement projects of various assets under many different scenarios. The 2004 Study approached replacement costs from the perspective of SCE operations and maintenance personnel who had an average of 21 years of experience working with T&D assets. These subject matter experts, who had experience performing and supervising work activities, reviewed and assessed the time and work requirements for each of several scenarios including total time spent on the project, equipment requirements, and crew size requirements. The work activities were evaluated and separated into installation and removal activities. The experts compared the results from the study to the existing allocations in the Standard Rates Table and determined that no update to the Standard Rates Table was required because the estimated costs of removal were not overstated using the existing process.

[36] The nine accounts listed on this table are the same ones for which SCE performed a per-unit analysis. Refer to WP SCE-09 Vol. 03, Book A, pp. 42-46 (Summary of Study Results).
[37] Refer to WP SCE-09 Vol. 03, Book A, pp. 52-172 (2004 Study Results).

In preparing this testimony, SCE revisited the rebuttal testimony of its outside depreciation expert from the 2015 GRC. Appendix A of the witness's rebuttal testimony was a copy of the 2004 study, and, in response to a question about the "historical documentation describing . . . the development of allocation factors used by SCE," the witness referred to the 2004 study in Appendix A (among other things) as evidence that "SCE used a very robust and detailed process to develop its allocation factors."[38] As a point of clarification, the allocation factors to which the witness referred in his testimony are not the Standard Rates Table allocations that formed the basis of SCE's depreciation request in the 2015 GRC and this 2018 GRC.[39] Rather, the witness testified to the allocation process and results from the 2004 Study together with his own observations and discussions with field personnel about cost assignment. Any lack of clarity in distinguishing between the Standard Rates Table allocations and the 2004 Study's allocations is not material as demonstrated in Table II-11, above. In fact, the results of the 2004 Study would have assigned a larger percentage of costs to removal than does the Standard Rates Table (by approximately 5%), as shown in that table.

b) <u>2006 Study</u> [40]

In 2006, SCE updated the 2004 Study in preparation for the 2009 GRC. Using a similar approach to the one utilized for the 2004 Study, SCE assembled a team of field operations experts to gather consensus estimates for labor hours for the job configuration scenarios used in the 2004 Study. The panel of study participants included overhead and underground experts from metropolitan and rural areas of SCE's service territory and others who reviewed job conditions, crew sizes, and labor hour estimates. In addition, as an enhancement to the 2004 Study, the field experts weighted the installation and removal activities by the likelihood of the scenarios' occurrence in the field. The results from the analysis were compared to the Standard Rates Table allocations, and the experts determined that if they were to update the Standard Rates Table allocations to incorporate the results of the 2006 Study, the cost of removal allocations would increase by over 5%. For this reason, and because SCE planned to implement new work planning and accounting software in 2010, SCE elected to continue using the Standard Rates Table.

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38 2015 GRC, SCE-26, Volume 3, p. 13. Later in the same volume, SCE's witness testified that the study in Appendix A shows that "the allocation factor <u>will</u> change based on more complex installations." *Id.*, p. 115 (emphasis in original). This was a reference to the study results, not to the way in which the Standard Rates Table allocations are applied today.

39 The Standard Rates Table was used to assign costs for several GRCs even prior to 2015.

40 Refer to WP SCE-09 Vol. 03, Book A, pp. 173-188 (2006 Study Results).

c) 2016 Study

(1) Background of Development of Compatible Units (CUs).

Before explaining the results of the 2016 Study, it is important to understand the development beginning in 2009 of the CUs that T&D employees use to plan, estimate, schedule and bill work. As explained in section II.C.2, above, DM incorporates the use of over 4,500 distribution CUs to assist planners with building cost estimates and scheduling work depending on the specific requirements of the job. When CUs are migrated to PowerPlan, they are mapped to CPRs and, for fixed asset accounting purposes only, the Standard Rates Table is used to allocate costs between removal and installation. The labor hours embedded in the CUs in DM are not used in the cost allocation process, but are important to facilitating the planning, scheduling, execution and closure of work orders for the T&D Operating Unit.

(2) 2009-2010 Labor Study

In 2009-2010, SCE undertook a year-long process to review and update the precursors to CUs, called "assembly kits," in preparation for integration into DM and SAP. This effort to examine CU hours was internally referred to as the "Labor Study," and it leveraged the results of the 2004 and 2006 Studies described above. The participants in the Labor Study—including construction managers and supervisors, foremen, trouble men, and standards and engineering teams from across SCE's service territory[41] — examined over 4,500 CUs of distribution assets and modified 1,800 of them.[42] The purpose was not to modify CUs for depreciation plant accounting purposes; rather, the intent of the study was to refine the "building blocks" of SCE's thousands of work orders (CUs) to improve planning, crew scheduling, estimating and pricing jobs and work order closure processes.

For three to four months of eight-hour days, the teams went line-by-line through SCE's old Material Management System (the old mainframe system in which the assembly kits resided) to remove obsolete items.[43] The initial part of the Labor Study was devoted to just clearing SCE's planning system of obsolete assembly kits. In the latter phase, the teams updated the labor hours

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41 Specifically, the experts came from the Metro West, Metro East, North Cost, Desert and Orange areas of SCE's service territory.

42 Separately, approximately 3,900 CUs for substation and sub-transmission assets were reviewed and migrated into SAP.

43 For example, if the Material Management System referred to a transformer with certain voltage requirements that were no longer applicable, that assembly kit was removed.

of the most commonly used CUs—transformers, switches and poles. The goal was to approximate labor hours as precisely as possible in order to improve crew scheduling times and cost estimates.[44] The team based labor hour estimates on the expert judgment and analysis of T&D employees, taking into consideration factors such as crew size, whether the work is performed energized, and whether the crews would have vehicle access. The work also involved examining individual CUs to assign updated removal and installation hours. The end result of the panel of experts' process was to review—and, if necessary, revise—the installation and removal hours (the removal hours assigned in the old assembly kits had been set at roughly half of installation hours). The updated labor values were developed using an average of the best, typical and worst case scenario specific to the installation and removal of a CU.

By 2010, the update process for the CUs had been completed, but SCE uses an ongoing governance structure to further update CUs on an ad hoc basis when required. There are three full-time employees whose job is focused on maintaining and updating CUs so that proposed/required changes flow through a standard process. The CU team receives an average of 22 requests each year to create new CUs (from planning, engineering, apparatus and meter services). The team also receives approximately 60 requests each year to review the accuracy of specific CUs (requesting review of hours or material components). Of the approximately one thousand field requests that have come through to examine CUs since 2010, less than a handful of requests actually resulted in changes to the installation/removal hours. This is due both to the comprehensiveness of the 2009-2010 Labor Study and the reality that work processes/practices do not change so significantly over time as to impact cost of removal ratios.

When planners use CUs to design and estimate particular jobs, they may—based on their own experience or through discussions with field personnel—supplement the labor estimates with additional Install, Removal or Expense labor hours on a work order-by-work-order basis. Any changes made to the project based on job complexity, additional crew tailboards, additional traffic control requirements, travel time, etc. are used for that specific work order only, and do not result in updating the master CU in the CU library. Updates to the CUs in the CU library occur occasionally. For example, in August 2012, a manager within the Street and Outdoor Lighting Organization requested that the CU team review the installation hours for street light photocells given his assessment that the 0.5

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[44] Work under Rules 2, 15, 16 and 20 benefit from accurate cost estimates built into CUs because those estimates form the basis for how customers are billed.

man hours for installation of this CU appeared high. The CU team pulled together a team of subject matter experts to assess and recommend a revision to the hours and determined that it should be reduced to 0.1 hours. Upon approval, the update was made in DM.

(3) 2016 Comparison of Standard Rates Table and CUs

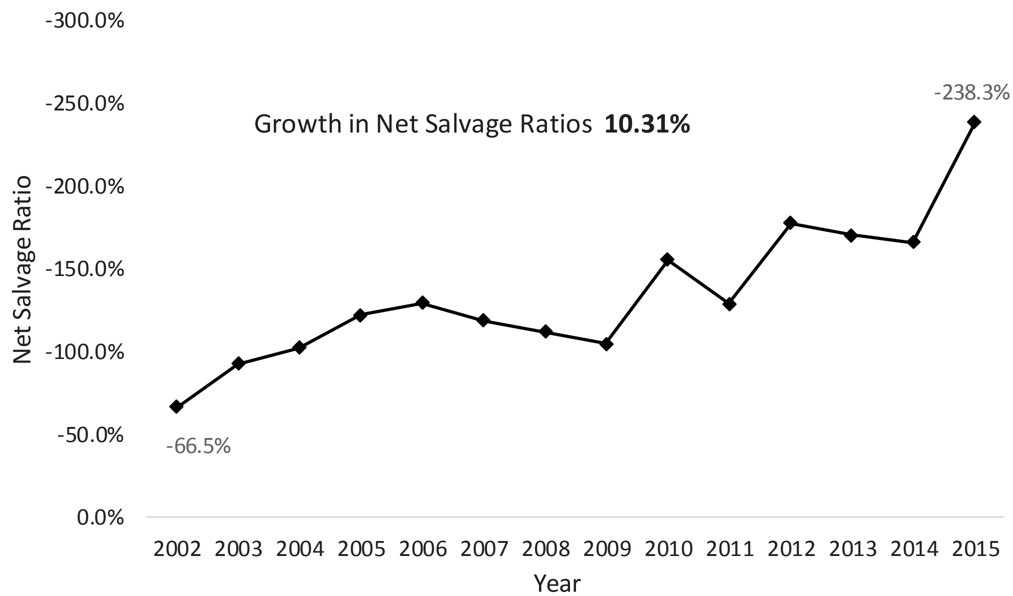
In 2016, SCE undertook a study comparing the Standard Rates Table allocations with what the allocations would be if SCE's fixed asset accounting process mapped the CU process described above. The scope of the study included a review of over 70,000 individually planned distribution orders developed in Design Manager in 2015, which collectively amounted to $1.7 billion, or approximately 84% of that year's capital expenditures. The review included comparing the installation and removal cost allocation from DM against the Standard Rates Table allocation for all 70,000 orders. The results indicate that the planners' CU-based approach, which is more detailed than the higher-level aggregation of the CPR-based allocations in the Standard Rates Table, results in cost assignments substantially similar to the Standard Rates Table (validated by the 2004 and 2006 Study results based on the panels of T&D experts).[45]

D. SCE's Experience with Increasingly Negative Net Salvage Rates

NSRs are typically negative because gross salvage is largely negligible compared to the cost of removal. The main reason for more negative NSRs can be attributed to the results of this mathematical formula: (1) costs to retire assets (numerator) in today's dollars divided by (2) the age and original cost of assets retired (denominator). Since 2002, SCE's 5-year rolling average NSR has more than tripled for distribution infrastructure, from -66% to -283% as shown in Figure II-7 below.

[45] Refer to WP SCE-09 Vol. 03, Book A, pp. 189-197 (2016 Study Results).

Figure II-7
Realized Net Salvage Ratios
Distribution Plant 2002-2015



For the last twenty years, SCE has experienced increasingly negative net salvage ratios for reasons explained in the next sections.

1. <u>The Average Age of Retirements is Increasing</u>

a) <u>Age and Inflation Impacts on Recorded Net Salvage Ratios</u>

An important consideration for the net salvage ratio calculation is that the numerator (net salvage cost) and the denominator (original cost) are stated in dollars spent at different points in time. The original cost retired in the denominator are measured in dollars from the time the plant was first placed in service (*i.e.*, older dollars) and the net salvage amounts in the numerator are measured when the plant is retired from service (*i.e.*, using more recent dollars). For example, a distribution pole placed into service in 1970 and retired in 2015 will have an original cost stated in 1970 dollars, but the removal costs will be incurred using 2015 dollars. Consequently, the temporal distance between installation and removal can have a significant effect on net salvage ratios primarily due to the effects of inflation. The effects of inflation are most apparent in the removal cost ratio, as the cost to retire (*i.e*., labor) is what is subject to the forces of inflation.[46]

[46] Refer to WP SCE-09 Vol. 03, Book A, pp. 198-201 (Experienced Net Salvage Rates) - *Depreciation Systems*, Frank K. Wolf and W. Chester Fitch, Iowa State University Press, pp. 53-55.

To illustrate the impact of inflation using a real life example, Table II-12, below, shows that the removal cost ratio increases with the age of the pole retired. Column C reflects the original cost of the pole being retired, while column D represents the removal cost in current dollars.

Table II-12
Plant Retirement and Removal Cost
(As Experienced for Distribution Poles – Account 364)
Data based on averages from 2009 to 2015

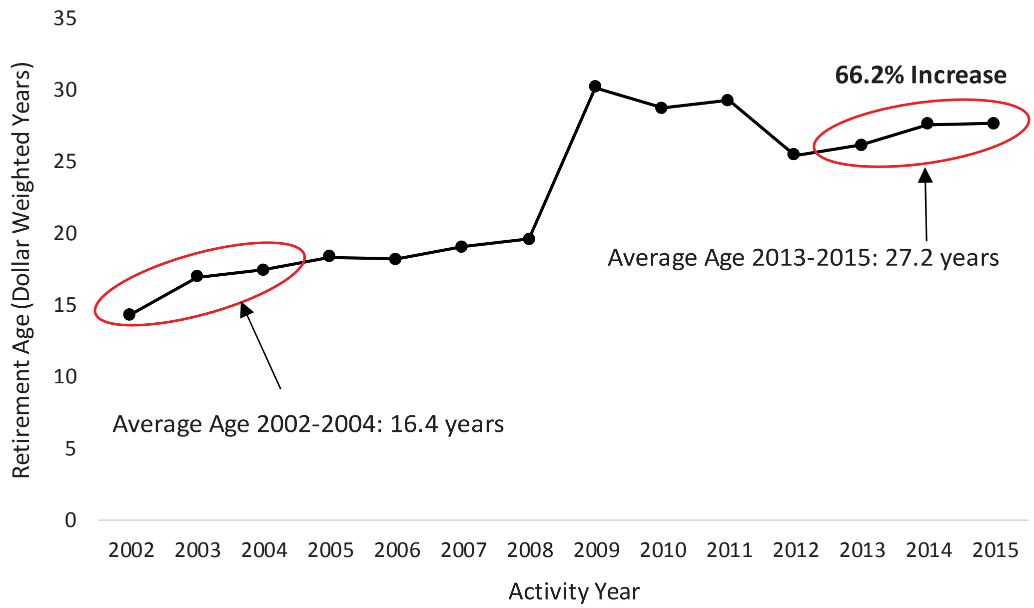
Vintage	Age of Pole Retired	Original Cost of Pole Retired	Per Pole Removal Cost	Removal Cost Ratio
A	B	C	D	E=D/C
2010	2.5	$7,599	$2,862	38%
2000	12.5	$3,547	$2,862	81%
1990	22.5	$1,413	$2,862	203%
1980	32.5	$622	$2,862	460%
1970	42.5	$369	$2,862	775%
1960	52.5	$167	$2,862	1717%

The table above demonstrates that as the age of the asset retired grows, the effects of inflation have an increasingly large impact on the realized removal cost ratio. This occurs because the average cost to install a pole in 1960 (Column C) would be significantly lower than the average cost to install a pole today, while the cost to remove each pole (Column D) is the same regardless of the age of the pole retired.

b) SCE's Aging Retirements

For multiple GRCs, T&D experts have testified about the advancing age of SCE's infrastructure. As the system matures, the average age of any retirement can be expected to be older than what was experienced in the past. As the system ages, the incidence of age related failures will increase. In fact, as shown in Figure II-8, below, this has been SCE's experience with distribution infrastructure for the past 13-years.

Figure II-8
Average Age Of Distribution Infrastructure Retired



As the age of T&D retirements increases, the original cost of the retirements has remained low, resulting in an increase in the experienced net salvage ratios.

2. <u>Total Cost Increases Affect Cost of Removal</u>

Over the last several rate cases, T&D experts have testified to the increasing need for capital to replace aging T&D infrastructure. This capital (including both the cost to remove and install) has been discussed by multiple witnesses over more than a decade of rate cases. In each case, witnesses have testified to cost pressures from the effects of: increasingly urban environments, increasing labor and contractor rates, increased permitting costs, more stringent environmental regulations, disposal fees, and system complexity.

For example, in the 2006 GRC the T&D Infrastructure Replacement witness provided the following still-relevant discussion on why the cost to retire assets in urban environments is higher than in rural areas:[47]

1) <u>Permitting</u>: Pole contractors are almost always required to obtain a city permit before initiating the work. In rural areas, permits are almost never required.

[47] 2006 GRC SCE-03 Vol 03 Part III pp. 14-15 and 2009 GRC SCE-03 Vol 03 Part III pp. 20-21.

2) Accessibility: Urban areas are frequently inaccessible by trucks and require that a crane be rented or that the pole be carried into the back yard and set manually. Rural areas are typically truck-accessible.

3) Congestion: Higher customers per circuit in urban areas contribute to higher congestion per pole than in rural areas. For example, an urban pole can be expected to be taller, as well as have more conductors, transformers, and cross-arms than a rural pole. In addition, the work may be performed on energized lines requiring specially trained crews and safety requirements.

4) Repairs: Urban areas frequently require that repairs are made to the concrete sidewalks, a requirement not typically necessary in rural areas.

Los Angeles County's population experienced significant growth[48] in the post-World War II period through the 1970s. This post-war population growth has increased the level of urbanization across SCE's service territory, putting upward pressure on costs. As a result of this, when assets originally installed in a rural environment are removed, the net salvage ratio reflects a very low original install cost for these assets. But these same assets are likely being replaced in a now more urban environment, adding to the upward pressure on removal cost. This experience can have a significant effect on the net salvage ratios—lower original cost (denominator) and higher cost of removal (numerator).

Given the increasing age of this infrastructure and the increasing urbanization associated with the post-war population growth, increases in the realized net salvage ratios is not surprising. As a result, however, the conditions present in SCE's service territory over this period of time may not be a realistic expectation of the future. In this case, and as further discussed immediately below, a per-unit analysis controls for this variation, and better represents SCE's expectation about the future levels of net salvage.

3. SCE's Per-Unit Analysis is Indifferent to the Realized Net Salvage Ratios

As described in Section B.1 of Chapter II, a per-unit analysis takes a different approach than Standard Practice U-4 in analyzing the expected levels of future net salvage. Rather than reviewing the relationship between historical costs of assets and the net salvage experienced in the past, the per-unit analysis uses the recorded average cost to retire each unit of property, and then applies per-unit

[48] 2009 GRC SCE-03 Vol 03 Part 3 p. 15 (SCE Territory – Population and System Demand).

costs to existing plant balances to forecast future net salvage given the anticipated timing of retirements. This approach to estimating future net salvage helps ensure that the results of the analysis are applicable to the mixture of plant that is serving customers today. Over time, as this mix of plant balances change, SCE will have the opportunity to reflect these changes in future per-unit analyses presented in its rate cases.

III.

DEPRECIATION STUDY

Chapter II, above, explained how SCE complied with the Commission's compliance directives and addressed the difference between traditional and per-unit analyses. The depreciation study addressing T&D assets, presented in Section A in Q&A format, was undertaken by an external consultant, Ronald E. White Ph.D. of Foster Associates Consultants, LLC. Dr. White provided SCE with life and net salvage parameters that SCE then used to calculate the proposed depreciation rates. SCE also conducted an in-house depreciation study of its Generation and G&I depreciable plant assets, discussed by an in-house SCE expert witness in Section B, below.

Unlike the Simulated Plant Record (SPR) procedure used in prior SCE rate cases, Dr. White performed an *actuarial* service life analysis using aged data from 2002 to 2015. In the 2012 GRC, the Commission stated that aged data is likely to be more reliable than SPR data, and it ordered SCE to "inform the Commission whether it used any aged data, and if not, when sufficient data is expected to be available."[49] In its 2015 GRC testimony, SCE stated that it began collecting aged data in 2008 and that it did not have sufficient aged data to perform an effective actuarial life analysis for the 2015 GRC.[50] This statement was based on an incorrect assumption that the Company began collecting aged data in 2008 when it implemented PowerPlan as its capital system of record.[51] In preparing its showing for this proceeding, SCE discovered that PowerPlan contains reconciled aged plant activity from 2002 forward. Thus, for this GRC, Foster Associates LLC performed an actuarial life analysis using the aged data from 2002 to 2015.[52]

Section A of Chapter III, below, which is in Q&A format, is the direct testimony of Dr. Ronald E. White of Foster Associates LLC.

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49 D.12-11-051 p. 685.

50 *See* Testimony in 2015 GRC, SCE-10, Vol. 02, Revision 1A, p. 33. SCE stated that it expected that aged data may become useful "in 10 years or so." *Id*.

51 PowerPlan was used only as the depreciation system of record prior to 2008.

52 SCE possesses some aged retirement data from 1994 through 2001 in Excel format outside of SCE's current capital system of record (PowerPlan). Neither SCE nor its outside expert evaluated or relied on the aged data in the 1994-2001 Excel sheets.

A. T&D - Average Service Life and Net Salvage Proposals

1. Development of Depreciation Rates

Q. PLEASE EXPLAIN WHY DEPRECIATION STUDIES ARE NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES.

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval.[53] A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life becomes more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process which establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the

[53] The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non–cash expenses) or cash inflows attributable to the use of that asset alone.

achievement of timely capital recovery for a regulated utility.

It is also important to recognize that revenue associated with depreciation is a significant source of internally generated funds used to finance plant replacements and new capacity additions. This is not to suggest that internal cash generation should be substituted for the goals of depreciation accounting. However, the potential for realizing a reduction in the marginal cost of external financing provides an added incentive for conducting periodic depreciation studies and adopting proper depreciation rates.

Q. PLEASE DESCRIBE THE PRINCIPAL STEPS INVOLVED IN CONDUCTING A DEPRECIATION STUDY.

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and cost of removal. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the Company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

Average and future net salvage rates are ideally estimated from a historical analysis of the cost per unit to install and the net cost per unit to retire major retirement units. A per unit analysis explicitly recognizes that the cost per unit to retire an asset is independent of the age of the asset when it is retired from service. The cost to retire a foot of conductor today, for example, is no different for a conductor that was installed yesterday or a conductor that was installed many years ago. As a result, percentage rate required to accrue for $5 per foot of removal expense on a conductor costing $10 per foot to install is twice the rate required to accrue the same amount of removal expense on a conductor costing $20 per foot to install.

Although a per unit analysis of installation and retirement costs is the most desirable treatment of net salvage, time and cost considerations (as well as the availability of the required data) often dictate a less rigorous analysis. Net salvage rates are frequently developed from a historical analysis using a three to ten–year moving average of the ratio of realized salvage and cost of removal to associated retirements. Net salvage estimates are also obtained from engineering studies of the cost to dismantle or abandon existing facilities.

2. 2016 Service–Life Study

Q. DID SCE PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR ESTIMATING SERVICE LIFE PARAMETERS?

A. Yes. Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

Q. HOW WERE SERVICE–LIFE ESTIMATES DERIVED FOR SCE PLANT AND EQUIPMENT?

A. As noted above, the first step in estimating service lives is called *life analysis*. All transmission, distribution and general depreciable plant accounts were analyzed using a technique in which first, second and third degree polynomials were fitted to a set of observed retirement ratios. The resulting function was expressed as a survivorship function, which was numerically integrated to obtain an estimate of the average service life. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data. Service life indications derived from the statistical analyses were blended with informed judgment and expectations about the future to obtain an appropriate projection life curve for each plant category. The analysis of each plant account is contained in Appendix A.

Q. PLEASE EXPLAIN IN GREATER DETAIL HOW LIFE ANALYSES WERE CONDUCTED IN THE 2016 STUDY.

A. The fundamental probability distribution of interest in estimating the service life of industrial property is called a *hazard function*. This function, which is also used in reliability theory, is an equation that describes the conditional probability of retirement (called a *hazard rate*) during an age interval given survival to the beginning of the interval. So, for example, the probability that plant that has been in service, say for 5 years, will be retired during the 6^{th} year is a conditional probability of retirement. In other words, the probability is conditioned upon having achieved an age of 5 years.

Graduating or smoothing observed hazard rates is an application of inferential statistics which draws inferences and predictions about a population based on samples of data taken from the population of interest. Projection lives and projection curves are population parameters "inferred" from a statistical analysis of the underlying forces of retirement described by probability distributions.

The object of a statistical analysis of plant retirements is to find the form of an equation that best describes the conditional probabilities of retirement, where the form of the equation is driven by the underlying forces of retirement. Any number of equations can be considered as candidates for selection. The so–called Iowa curves are a family of distributions most often used in conducting depreciation studies.

Each Iowa curve has a unique hazard function derived from the ratio of its retirement frequency distribution to its survivor distribution. Unfortunately, however, Iowa hazard functions cannot be written as explicit equations. It is for this reason that polynomials of the form $y = a + bx + cx^2 + dx^3$ are used to estimate hazard functions. The variable y is the hazard rate and x is the age interval of the rate.[54] A polynomial can be transformed into a survivor function and plotted against an Iowa curve to visually observe the derived survivor curve expressed as an Iowa curve.

The problem, therefore, is to estimate the coefficients (*i.e*., *a*, *b, c* and *d*) of the polynomial from an estimate of hazard rates derived from a sampling of historical retirements recorded for a plant category. Different estimators of the hazard rate can be used depending upon the desired statistical properties of the estimator. The ratio of retirements to exposures is most often used for depreciation studies.

Coefficients were estimated in the 2016 study using *Orthogonal Polynomials.* An orthogonal polynomial is not a special form of a polynomial. It is a procedure developed by Tchebysheff to estimate the coefficients of a polynomial (using regression) without rewriting the normal equations for each successive power of the polynomial. The coefficients of a second degree equation, for example, can be derived from a first degree equation without rewriting the equations used in a normal least squares regression.

Coefficients and polynomials were estimated for numerous trials or samples of retirements recorded over various bands of activity years. An activity year is the calendar year in which retirements were recorded. Retirements from vintages of like ages are combined to increase the size of the samples from which hazard rates are estimated. The motivation for examining various bands of activity years is to observe service–life trends to the extent they may be detectable.

Each polynomial was transformed or converted to a survivor function (or survivor curve when plotted) from which an estimate of the projection life was derived. The polynomial form of the hazard functions were also plotted and visually inspected as an aid to better understanding the forces of retirement acting upon a plant category.

Polynomials transformed to survivor functions were then fitted to Iowa–type curves with projection lives set equal to those derived from the polynomials. The purpose of fitting to Iowa curves is to obtain service–life descriptors more familiar to users of Iowa curves. It would be more obscure and less informative to describe survivor curves by the coefficients of a polynomial.

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[54] The reason polynomials are limited to a third degree term (*i.e*., a polynomial having an x^3 term) is that some low modal Iowa curves exhibit two inflection points in a plot of the hazard function.

Q. WERE FACTORS OTHER THAN SERVICE–LIFE INDICATIONS DERIVED FROM THE STATISTICAL STUDIES CONSIDERED IN ESTIMATING SERVICE–LIVES FOR SCE?

A. Yes. As discussed earlier, estimating service lives is a two–step procedure. The first step (life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of past forces of retirement acting upon a plant category and an estimate of the projection life implied from observed historical experience.

The second step (life estimation*)* is concerned with predicting the expected remaining life of property units still exposed to forces of retirement and the service life of future plant additions. It is a process of blending the results of a life analysis with information (mostly qualitative) and informed judgment to obtain an appropriate projection life and curve descriptive of future expectations. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future. Both life analysis and life estimation require an understanding of the limitations of statistical studies and the need for reasonable and informed judgment.

Q. ARE FACTORS YOU CONSIDERED IN LIFE ESTIMATION DESCRIBED IN THE 2016 STUDY?

A. Yes. Appendix A contains a narrative explanation of both quantifiable factors (life analyses) and non–quantifiable factors (largely life estimation) considered by Foster Associates in recommending appropriate projection lives and curves for SCE. In those instances in which statistical indications could not be derived and/or observed indications were adjusted for operational, financial or ratemaking reasons, Foster Associates deferred to SCE in the selection of appropriate service lives.

Q. IS A PROJECTION LIFE THE SAME AS AN AVERAGE SERVICE LIFE?

A. No. A projection life is an estimate of the mean service–life of the population from which retirements are a random sample. The *average* service life of a plant category is a function of the age distribution of surviving plant (*i.e.*, plant currently in service by vintage–year of installation) and a selected level of asset grouping such as broad–group, vintage–group or equal-life group. If retirements are distributed over varying ages, the broad–group procedure (which assumes that each vintage has the same average service life) is the only grouping of assets that will produce an average service life equal to the projection life estimated for a plant category.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR SERVICE–LIFE STUDY.

A. Current and recommended projection lives and dispersions are summarized in Table III-13 below.

Table III-13
Service Life Statistics

	Current		Recommended	
Account Description	P-Life	Dispersion	P-Life	Dispersion
A	C	D	E	F
Transmission Plant				
352.00 Structures and Improvements	55.00	S3	55.00	L1
353.00 Station Equipment	45.00	R0.5	40.00	L0.5
354.00 Towers and Fixtures	65.00	R5	65.00	R5
355.00 Poles and Fixtures	50.00	R0.5	65.00	SC
356.00 Overhead Conductors and Devices	61.00	R3	61.00	R3
357.00 Underground Conduit	55.00	R3	55.00	R3
358.00 Underground Conductors and Devices	40.00	R2.5	45.00	S1
359.00 Roads and Trails	60.00	SQ	60.00	R5
Distribution Plant				
361.00 Structures and Improvements	42.00	R2.5	50.00	L0.5
362.00 Station Equipment	45.00	R1.5	65.00	L0.5
364.00 Poles, Towers and Fixtures	47.00	L0.5	55.00	R1
365.00 Overhead Conductors and Devices	45.00	R0.5	55.00	R0.5
366.00 Underground Conduit	59.00	R3	59.00	R3
367.00 Underground Conductors and Devices	45.00	R0.5	43.00	R1.5
368.00 Line Transformers	33.00	R1	33.00	S1.5
369.00 Services	45.00	R1.5	45.00	R1.5
370.00 Meters	20.00	R3	20.00	R3
373.00 Street Lighting and Signal Systems	40.00	L0.5	48.00	L1
General Plant				
390.00 Structures and Improvements	38.00	R3	45.00	R0.5

Table 1. Service Life Statistics

3. <u>2016 Net Salvage Study</u>

Q. WHY IS NET SALVAGE RECOGNIZED IN THE COMPUTATION OF DEPRECIATION ACCRUAL RATES?

A. Depreciation is a measurement of the service potential of an asset that is consumed during an accounting interval. The cost of obtaining a bundle of service units (*i.e.,* a future net revenue stream) is represented by an initial capital expenditure which creates a revenue requirement for return and depreciation, and a future expenditure which creates a revenue requirement for cost of removal reduced by salvage proceeds. The matching principle of accounting provides that both the initial and future expenditures should be allocated to the accounting periods in which the service potential of an asset is consumed. The standard or criterion that should be used to determine a proper net salvage rate is, therefore, cost allocation over economic life in proportion to the consumption of service potential. If some other standard (such as cash flow or revenue requirements) is considered more important in setting depreciation rates, then cost allocation theory must be abandoned as the foundation for depreciation accounting.

The need to include net salvage in the development of depreciation rates is widely recognized and accepted by a substantial majority of state regulatory commissions as a standard ratemaking principle. The FERC Uniform System of Accounts (USoA), for example, describes depreciation as the "… loss in service value" where service value is defined as "… the difference between original cost and net salvage value of gas plant." Net salvage value means "the salvage value of property retired less the cost of removal."

The economic principle underlying both the accounting and ratemaking treatment of net salvage is that in addition to return *of* and return *on* invested capital and taxes, a revenue requirement for removal expense (or a reduction in the revenue requirement attributable to gross salvage) is created when an asset is placed in service. It is customary and appropriate for regulated utilities, therefore, to include a net salvage component in its depreciation rates to more nearly achieve the goals of depreciation accounting and to equitably distribute the revenue requirement for removal expense over the period in which the assets that created the requirement are used to provide utility service.

Q. WHAT IS A FUTURE NET SALVAGE RATE?

A. Future net salvage (in percent) is the sum of future net salvage (*i.e.*, gross salvage less cost of removal) at a given observation age divided by the surviving plant investment at that age.

Q. WHAT IS AN AVERAGE NET SALVAGE RATE?

A. Average net salvage (in percent) is the sum of realized and future net salvage divided by the plant investment at age zero. Stated differently, average net salvage is the total estimated salvage less cost of removal for a vintage (or group of vintages) expressed as a percent of the original vintage additions. Future net salvage is related to the surviving plant of a vintage (or group of vintages) whereas average net salvage is associated with the original vintage addition.

Q. ARE YOU FAMILIAR WITH THE COMMISSION'S DECISION IN SCE'S 2015 GRC (D.15-11-021) REGARDING NET SALVAGE PROPOSALS?

A. Yes. In the 2015 GRC Decision, the Commission directed SCE to provide more detail in support of its net salvage proposals for at least five of the largest accounts, as measured by proposed annual depreciation expense. At a minimum, this detail shall include:

1. "A quantitative discussion of historical and anticipated future Cost of Removal (COR) on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This discussion should identify and explain the key factors in changing or maintaining the per–unit COR."
2. "A quantitative discussion of historical and anticipated future retirement mix (i.e., retirements among different asset classes), identifying and explaining the key factors in changing or maintaining this mix."
3. "A quantitative discussion of the life of assets and original cost of assets being retired, in relation to the COR, on both a historical and anticipated future basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics."
4. "An account–specific discussion of the process for allocating costs to COR."[55]

a) Directive No. 1

Q. WERE HISTORICAL AND FUTURE NET SALVAGE COSTS DERIVED ON A PER UNIT BASIS IN COMPLIANCE WITH THE COMMISSION'S FIRST DIRECTIVE?

A. Yes. Per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table III-14, below.

[55] D.15-11-021, pp. 554-555.

Table III-14
Per Unit Net Salvage Accounts

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 2. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both the historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates. Gross salvage is generally small in relation to cost of removal.

Historical per unit ratios were examined and compared with the ratio of realized net salvage to the associated retirements. In most instances, the ratio of net salvage to retirements is greater than historical per unit ratios observed over the period 2009–2014. This is predictable since net savage is recorded in current dollars and retirements are recorded in historical dollars.

Future per unit ratios were derived using a weighted average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios. This treatment was decided after multiple meetings and discussions with SCE engineers and subject matter experts who reported that SCE has no planned or expected changes in retirement activities that would measurably change average net salvage per unit values recorded in recent activity years. Other than recognizing future inflation, historical net salvage per unit values were therefore retained in the forecast of future net salvage rates. Subpopulations and average historical per unit net salvage costs are summarized in Table III-15 below.

Table III-15
Average Net Salvage Per Unit to Retire

Account and Subpopulation	12/31/2015 Plant	12/31/2015 Percent	Avg. Add Per Unit*	Avg. NS Per Unit*
A	B	C	D	E
354.00 Towers and Fixtures				
A. Towers Soley Owned >= 230 kV	$ 1,139,621,027	91.8%	$610,475	$ 57,365
B. Towers < 230 kV, Common and Other	101,453,733	8.2%	321,711	6,628
	1,241,074,760	100.0%		
355.00 Poles and Fixtures				
A. Wood, Fiber Glass and Composite	375,781,560	47.2%	14,939	4,517
B Light Duty Steel	419,049,403	52.6%	18,775	10,281
C Retaining Walls	1,261,756	0.2%	145,988	(36,480)
	796,092,719	100.0%		
356.00 Overhead Conductors and Devices				
A. Conductor < 220 kV	202,769,129	18.7%	11	5
B Conductor >= 220 kV	739,015,019	68.3%	38	6
C Disconnect Switches	27,761,688	2.6%	42,650	11,921
D Ground Wire	113,151,541	10.5%	20	(46)
	1,082,697,377	100.0%		
364.00 Poles, Towers and Fixtures				
A Wood, Fiberglass and Steel Poles	2,191,572,261	100.0%	6,882	2,700
	2,191,572,261	100.0%		
365.00 Overhead Conductors and Devices				
A Overhead Conductor	946,696,334	68.6%	8	3
B Switches	347,104,388	25.1%	12,828	3,384
C Breakers, Reclosures and Other	87,013,183	6.3%	2,404	358
	1,380,813,905	100.0%		
366.00 Underground Conduit				
A Pull and Slab Boxes	447,741,061	13.0%	949	1,305
B Below Ground Conduit	789,932,796	22.9%	23	1
C Vaults	324,651,530	9.4%	7,584	23,101
D Excavation Trenches	16,836,983	0.5%	(77)	
E Manholes and Other	157,068,859	4.6%	1,258	462
	1,736,231,229	50.3%		
367.00 Underground Conductors and Devices				
A Underground Cable	4,452,641,073	84.6%	25	10
B Breakers, Switches, Reclosures	809,879,908	15.4%	8,567	4,896
	5,262,520,981	100.0%		
368.00 Line Transformers				
A Overhead Transformers	1,045,618,106	30.3%	2,655	561
B Underground Transformers	1,262,937,734	36.6%	5,899	1,459
C Lightening Arresters and Fuse Holders	749,306,101	21.7%	924	161
D Switches, Breakers, Capacitors, etc.	393,008,343	11.4%	5,658	960
	3,450,870,284	100.0%		
369.00 Services				
A Underground Conductor	783,834,596	61.2%	301	221
B Overhead Conductor	387,892,896	30.3%	236	123
C Risers	63,694,659	5.0%	881	450
D Underground Conduit and Other	44,872,497	3.5%	12	0
	1,280,294,648	100.0%		

*2009 - 2015

Table 3. Average Net Salvage Per Unit to Retire

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account. The formulation of per–unit net salvage rates is contained in Appendix B.

Q. PLEASE SUMMARIZE THE FINDINGS OF YOUR PER UNIT NET SALVAGE ANALYSIS.

A. Future net salvage rates derived with inflation rates ranging between zero (0) and three (3) percent are summarized in below.

Table III-16
Future Net Salvage Rates

Account Description	Projection Curve	Inflation Rate 0%	1%	2%	2.72%
A	B	C	D	E	F
354.00 Towers and Fixtures	65-R5	104%	125%	155%	185%
355.00 Poles and Fixtures	65-SC	90%	155%	295%	499%
356.00 Overhead Conductors and Devices	61-R3	114%	141%	178%	210%
364.00 Poles, Towers and Fixtures	55-R1	180%	249%	361%	488%
365.00 Overhead Conductors and Devices	55-R0.5	195%	272%	397%	538%
366.00 Underground Conduit	59-R3	108%	170%	276%	401%
367.00 Underground Conductors and Devices	43-R1.5	112%	150%	205%	261%
368.00 Line Transformers	33-S1.5	27%	33%	40%	47%
369.00 Services	45-R1.5	178%	231%	309%	387%

Table 4. Future Net Salvage Rates

Q. HOW WERE NET SALVAGE RATES ESTIMATED FOR ACCOUNTS NOT INCLUDED IN THE PER UNIT NET SALVAGE ANALYSIS?

A. A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was used to: a) estimate a realized net salvage rate; b) detect the emergence of historical trends; and c) establish a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were blended with judgment and historical net salvage indications in developing estimates of the future. The analysis of net salvage is contained in Appendix A.

Although future per unit ratios applied to a forecast of future retirements provides a more rigorous estimate of future net salvage rates, it is the opinion of Foster Associates that the ratio of realized net salvage to retirements provides reasonable estimates of future net salvage rates to the extent that future inflation is similar to the past. Estimating depreciation rates, however, is not an exact science; errors of estimate in both service lives and nets salvage rates will always remain.

b) Directive No. 2

Q. WERE HISTORICAL AND FUTURE RETIREMENT MIXES EVALUATED IN COMPLIANCE WITH THE COMMISSION'S SECOND DIRECTIVE?

A. Yes. As noted above, each of the nine plant accounts was divided into one or more subpopulations of major equipment categories. The mix of equipment classified in each subpopulation and the size of each subpopulation as a percent of the current investment in each related plant account were reviewed by SCE engineering and plant accounting personnel. No key factors were identified from this review that would suggest the future retirement mix or relative size of each subpopulation will be significantly different from the current composition and grouping of subpopulations.

c) Directive No. 3

Q. WERE RECOMMENDED LIFE CHARACTERISTICS AND NET COST OF REMOVAL INTEGRATED IN COMPLIANCE WITH THE COMMISSION'S THIRD DIRECTIVE?

A. Yes. The directive to provide a quantitative discussion of asset life and original cost of assets being retired, in relation to the COR on a historical basis, was interpreted to mean an examination of the average age of retirements associated with the recording of COR. Work papers supporting Appendix A provide a summary (Schedule E) of the average age of retirements and recorded COR for each of the per unit accounts. Although net salvage is often recorded subsequent to the recording of retirements, it can be observed that COR as a percent of retirements is a function of the age of retirements and generally increases with increases in the average age.

As noted earlier, a prospective per–unit analysis should be designed to produce estimates of future net salvage rates respecting the principle that the net cost per unit to retire an asset in independent of the age of the asset when it is retired from service. The percentage rate applied to the cost of an old asset to accrue the same cost per unit to retire a newer asset, however, depends upon the relative difference in the cost per unit incurred to install the assets. Integration of per unit ratios with life characteristics necessitates forecasting vintaged retirements using projection lives and curves estimated for each plant account.

Estimates of the amount and timing of future net salvage were derived from an application of the ratio of per unit net costs to retire and per unit installed costs of each vintage within a subpopulation, to future retirements (forecasted by vintage) using the projection lives and curves estimated in the statistical life studies. Inflation rates ranging between zero and three percent were employed in the analysis to recognize the likelihood of increasing net salvage solely attributable to inflation.

Other than a range of assumed inflation rates and parameters estimated in the service–life studies, no elements of qualitative judgment were required or exercised in estimating future net salvage rates from the per unit analysis.

d) Directive No. 4

Q. THE COMMISSION'S FOURTH DIRECTIVE IN APPLICATION A.13–11–003 WAS TO PROVIDE AN ACCOUNT–SPECIFIC DISCUSSION OF THE PROCESS FOR ALLOCATING COSTS TO COR. HAS SCE COMPLIED WITH THIS DIRECTIVE?

A. Yes. The process for allocating costs is described in the direct testimony of SCE witness Alan Varvis in this Exhibit.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

B. Generation and G&I - Average Service Life and Net Salvage Proposals

1. Purpose and Scope

This chapter covers the average service lives and net salvage proposals for SCE's Generation and General & Intangible (G&I) assets. For G&I assets, SCE proposes to retain the same service lives and net salvage rates as authorized in the 2015 GRC Decision.

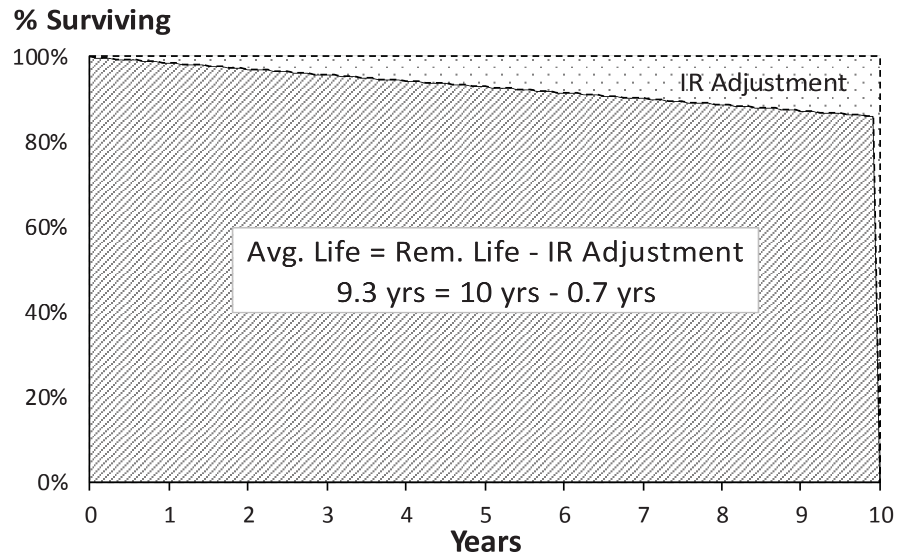
2. Generation-Related Property

a) Average Service Lives for Generation Assets

Generating facilities are life span assets that consist of large plant assets expected to retire all at one time, with some smaller components retiring earlier during the service life of the plant (called "interim retirements"). To determine the *average* life of the plant asset, SCE adjusts the life span downward to take into account the shorter-lived interim retirements. The life span for a generating facility as a whole depends on the factors affecting the final shutdown: operating license, fuel and resource availability, contractual obligations, the relative efficiency of the generating units, and so forth. The total life span is determined largely as an engineering judgment based on the factors previously mentioned.

Interim retirements consist of such items as pumps, motors, and other individual generating components that retire depending on the factors specifically affecting them—wear and tear, reliability, obsolescence, and so forth. The impacts of the life span and the interim retirements on the overall average service life of the plant asset are determined separately. SCE considered the interim retirement adjustment first by estimating the future level of annual interim retirements as a percent of the plant balance (*i.e.*, an interim retirement rate or IR rate). The estimate of an IR rate is made by analyzing the historical levels of interim retirements. The determined annual IR rate is applied to the current plant balance over the remaining life of the plant to determine the necessary adjustment to the overall remaining life of the generating station. For example, if a generating plant has a 10-year remaining life and an IR rate of 1.4 percent per year, then about 14 percent of the current plant balance would retire as interim retirements (10 years times 1.4 percent year) and the remaining 86 percent would retire as a final retirement. The resulting survivor curve is shown in Figure III-9.

Figure III-9
Life Span Survivor Curve*



* *Remaining Life Span = 10 years; IR Rate = 1.4%.*

As Figure III-10 demonstrates, the average life is equal to the life span adjusted for the shorter life of the interim retirements. The remaining life adjustment is calculated as follows:

Figure III-10
Life Span: Remaining Life Adjustment

$$\text{Remaining Life Adjustment} = \frac{\text{Rem. Life Span x IR Rate}}{2} \times \text{Rem. Life Span}$$

$$\text{0.7 Years} = \frac{\text{10 Years x 1.4\%}}{2} \times \text{10 Years}$$

Table III-17 summarizes SCE's proposed generation average service lives as compared to those authorized in the 2015 GRC. What follows is a plant-by-plant discussion of the proposed average service lives.

Table III-17
Generation Service Life Spans

Generation Facility	Life Spans	
	Authorized	Proposed
A	B	C
Nuclear Production - Palo Verde	30.5 yrs	28.0 yrs
Hydro Production	26 yrs	19.9 yrs
Other Production		
Pebbly Beach	45 yrs	25 yrs
Mountainview	35 yrs	35 yrs
Peakers	35 yrs	35 yrs
Solar Photovoltaic	25 yrs	20 yrs
Fuel Cells	10 yrs	10 yrs
Energy Storage	N/A	10 yrs

(1) Palo Verde Nuclear Generating Station (PVNGS)

The Nuclear Regulatory Committee (NRC) licenses for PVNGS Units 1, 2, and 3 end June 1, 2045, April 24, 2046, and November 25, 2047, respectively, resulting in an average 30.5 year remaining life span for the station as of December 31, 2015. In addition, recent retirement activity supports adjusting the average remaining life down by 2.5 years to 28 years to account for the effect of interim retirements.

(2) Hydro Generation

SCE's hydro generation system consists of 76 generating units and associated facilities accounted for in 60 different accounting locations. Nearly all of SCE's hydro facilities (99 percent) is covered by FERC licenses. The licenses have a variety of termination dates—from expired (either in the process of being relicensed or decommissioned) to 2046. The total life span of SCE's current license periods for those plants without expired licenses range between 5 and 30 years. Recently, FERC has issued renewals with license periods averaging 40 years.

Prior license renewal does not guarantee that the generating plant will last indefinitely. There are no guarantees that the FERC will continue to grant the company licenses or that the generating units will continue to be economic. Moreover, the individual components making up a generating station will continue to wear out, be retired, and need to be replaced. Consequently, SCE proposes that the hydro generation plant be depreciated over the remaining life spans associated with the individual FERC licenses.[56] For generating stations with already expired, or within five years of license termination, SCE proposes that the life spans be extended by the estimated license life in its current FERC license applications.[57]

(3) Pebbly Beach

The Pebbly Beach generating station consists of six diesel generating units, ranging in capacity from 1.0 MW to 2.8 MW. In its last GRC, SCE was authorized a 45-year average service life for this account on the basis that each of the six units would experience increasing risk of obsolescence and failure after two overhaul cycles (approximately 22 years between overhauls). Because of the difficulty in sourcing alternative supply of generation for Catalina Island, SCE engineers expect these units to remain in-service for the foreseeable future. However, to help ensure continued operations, SCE engineers state that the units require a zero-time overhaul[58] after approximately 100 to 120 thousand operating hours. Based on SCE's actual experience with the operations of these units, the time between overhauls is approximately 25 years.

For example, the SCE is proposing to reduce the average service life for this account from the currently authorized 45 years to 25 years. This change is concurrent with moving the start of the amortization period from the vintage year to the date of the last overhaul. This 25-year life allows SCE to recover the cost of each zero-time overhaul over its useful life with little impact to the remaining life as shown in Table III-18 below.

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56 In the case of the 1 percent of hydro plant not covered by a FERC license, SCE applies the average life determined for the plant that is covered by FERC license.

57 The average application license period is 44 years. The exception to this life span extension is the amortization period for the hydro relicensing costs. These relicensing costs are only amortized over the associated license period for which they were spent.

58 A zero-time overhaul restores operations of the unit to like-new operating conditions.

Table III-18 [59]
Comparison of SCE's 2015 Authorized and 2018 Proposed Lives for Pebbly Beach Generating Station

Line No.	Item	2015 GRC Authorized	2018 GRC Proposed
1.	Average Start Date	1986	2006
2.	Proposed ASL	45	25
3. = 1.+2.	Estimated Ret. Date	2031	2031
4. = 3. - 2015	Rem. Life a/o 1/1/2016	15.7	15.5

There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 15.5 years for this account.

(4) Mountainview

SCE is proposing to retain Mountainview's currently authorized 35-year life span as established in the 2015 GRC Decision. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 25 years for this account.

(5) Peakers

SCE is proposing to retain the currently authorized 35-year average service life for Peaker. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 28 years for this account.

(6) Solar Photovoltaic

The currently authorized average service life for Solar Photovoltaic (PV) equipment is 25 years. SCE is proposing to return to the previously authorized 20-year average service life. Based on discussions with SCE engineers[60] the major components of this account will have significantly shorter service lives than the currently authorized 25-year life. Engineers indicate that the

[59] Refer to WP SCE-09 Vol. 03, Book A, p. 203 (Generation Life Spans).
[60] Refer to WP SCE-09 Vol. 03, Book A, p. 204 (Generation Life Spans).

equipment in this account is expected to fail significantly sooner than the currently authorized 25-year authorized life. For example, the three main components[61] include:

- Solar Panels – 10-12 years
- Inverters – 5-8 years (warrantied for 5 years)
- Control System – 6-8 years for obsolescence to set in.

In addition, the rooftop leases granting SCE the rights to use the rooftop facilities is currently 20-years. Given the uncertainty of lease renewal and short expectations about the life of the equipment, a 20-year life proposal is reasonable for this account. There have been insufficient interim retirements to estimate an IR rate for this plant; consequently both the remaining life span and the average remaining life are 16 years for this account.

(7) Fuel Cells

SCE owns and operates two fuel cell demonstration facilities. The plants, located at California State University, San Bernardino (CSUSB) and University of California Santa Barbara (UCSB) were installed in September 2012 and October 2013 respectively. SCE is proposing to retain the currently authorized 10-year average service life. This proposal is consistent with our expectations that title to the demonstration facilities will be transferred to the site owners at the end of their 10-year lease.

(8) Energy Storage

The Commission has required SCE to procure and install 580 MW of energy storage facilities in its service territory by 2020. These facilities represent emerging technology and face significant risk of technological obsolescence in the future. SCE estimates the life of Energy Storage by the design life, cycle times of the proposed facilities, discussion with engineers, reviewing of reputable engineering studies and benchmarking with industry peers. SCE proposes a 10-year average service life for the Energy Storage and this represents a reasonable estimate of the expected life of these facilities when they are deployed.

b) Net Salvage Rates for Generation Assets

As discussed above, generation properties are retirement units that will retire in full at a specific time. Although there are interim additions and retirements that occur over the service life of the plant, the plant as a whole is subject to final retirement. SCE's generating plants—Palo Verde,

[61] *Id*.

Hydro, Pebbly Beach, Mountainview, Peakers, Solar Photovoltaic, Fuel Cell—fit these characteristics. The net salvage for SCE's generation plants is considered using two basic elements—interim retirement net salvage and final retirement net salvage (*i.e.*, "decommissioning")—which are estimated separately. The final retirement net salvage entails an engineering estimate of the cost to remove and dispose of the plant and equipment existing at the time of the station's final shutdown.

In contrast to final retirements, interim retirement net salvage is the removal cost associated with the numerous small retirements occurring over the life of the generating station. This net salvage is estimated based upon an analysis of recorded interim net salvage ratios similar to the approach followed for mass property. Finally, the interim and final net salvage amounts are combined based upon the associated plant dollars to determine a total weighted average net salvage for the generating station. The estimated decommissioning costs at retirement are shown in the Table III-19 below. Interim retirement net salvage is relatively small with only a minor impact to amortization levels.

Table III-19
Generation Removal Cost

	Decommissioning		Interim Retirement NS	
Plant	Auth.	Prop.	Auth.	Prop.
A	B	C	D	E
Nuclear Production - Palo Verde	Covered Under NDCTP		-	$2.1 M
Hydro Production	-	-	$1.9 M	$4.5 M
Other Production				
Pebbly Beach	$6.6 M	-	-	-
Mountainview	$16.3 M	$16.2 M	-	-
Peakers	$12.1 M	$14.9 M	-	-
Solar Photovoltaic	$81.9 M	$80.8 M	-	-
Fuel Cells	-	-	-	-
Energy Storage	N/A	-	-	-

The net salvage estimates for generating stations will differ significantly depending upon a variety of factors. Although the net salvage consists of both interim retirement net salvage and final decommissioning costs, the scale of the decommissioning costs will generally drive the overall net salvage levels requested. In the case of Palo Verde, only interim retirement net salvage is included in the filing and is estimated to be zero percent at this time. The Commission will address the final decommissioning costs of Palo Verde in the Nuclear Decommissioning Cost Triennial Proceedings. The following sections discuss the decommissioning estimates for the respective generation facilities.

(1) Palo Verde Net Salvage

As previously mentioned, only interim retirements are addressed in this filing. While SCE did not request for interim retirement net salvage cost in its prior rate cases, recent retirement activity supports a modest increase. As such, SCE is proposing to include the interim retirement net salvage rates as shown in Table III-20, below.

Table III-20[62]
Palo Verde Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Land and Land Rights	0.0%	0.0%
Structures and Improvements	-0.15%	0.0%
Reactor Plant Equipment	-20.0%	-3.7%
Turbogenerator Units	-16.0%	-5.9%
Accessory Electric Equipment	-13.0%	-0.6%
Misc. Power Plant Equipment	-16.0%	-2.0%

(2) Hydro Net Salvage

With the exception of San Gorgonio Unit 2, which is an active state of decommissioning, SCE is not requesting net salvage for decommissioning at this time. SCE is continuing to remove/retire San Gorgonio Unit 2 and is requesting $6.4M for the capital expenditures expected to be incurred from 2016 to 2019.

Interim retirement net salvage ratios for interim retirements are calculated by analyzing the recent retirement history for the level of net salvage incurred during interim retirements. The ratio of net salvage (gross salvage less cost of removal) divided by the retirement values is used to arrive at the net salvage ratios shown in Table III-21, below.

[62] Refer to WP SCE-09 Vol. 03, Book A, pp. 205-214 (Palo Verde Interim Retirements).

Table III-21[63]
Hydro Interim Retirement Net Salvage

	Net Salvage Ratio (% of IRs)	Net Salvage Ratio (% of Plant)
Structures and Improvements	-150%	-10.9%
Reservoirs, Dams and Waterways	-250%	-5.6%
Water Wheels, Turbines & Generators	-50%	-9.5%
Accessory Electric Equipment	-150%	-10.6%
Misc. Power Plant Equipment	-20%	-1.9%
Roads, Railroads & Bridges	-100%	-11.5%

(3) Pebbly Beach Net Salvage

Due to the expectations that the diesel generators will continue to operate in the foreseeable future, SCE is not proposing to recover any decommissioning costs in this rate case. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(4) Mountainview Net Salvage

SCE compiled a list of equipment and facilities to be installed as part of the new generation facilities and itemized them by FERC plant account.[64] SCE then developed demolition costs for each component. The estimated decommissioning costs for Mountainview is $8.9 million (2012 dollars). SCE escalated the $8.9 million out to the end of the remaining life of the station, resulting in $16.2[65] million. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

(5) Peakers Net Salvage

In 2007, SCE commissioned Arcadis to perform decommissioning cost studies for each of its five Peaker units. Table III-22 below shows the current cost for each unit, totaling $7.7M. Escalated to the estimated year of final retirement produces a total future decommissioning cost of $14.9M.[66] Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

[63] Refer to WP SCE-09 Vol. 03, Book A, pp. 215-223 (Hydro Interim Retirements).
[64] Refer to WP SCE-09 Vol. 03, Book A, pp. 308-313 (Mountainview Decomm).
[65] *Id.*
[66] Refer to WP SCE-09 Vol. 03, Book A, pp. 225-291 (Peakers Decomm).

Table III-22
Peaker Decommissioning Costs ($000's)

Line No.	Peaker Unit	2015 ($) Decomm	Retirement Year	Retirement Year Decomm ($)
1.	Barre	$1,427	2042	$2,676
2.	Center	$1,414	2042	$2,652
3.	Grapeland	$1,593	2042	$2,987
4.	McGrath	$1,683	2042	$3,155
5.	MiraLoma	$1,604	2047	$3,407
		$7,722		$14,877

(6) Solar Photovoltaic Net Salvage

In 2011, SCE commissioned Worley Parsons to conduct a decommissioning study of its Solar Photovoltaic Equipment. The study resulted in a range of estimates between $300,000 and $547,000 per megawatt in 2011 dollars based on the type of facility installed. Lower cost estimates are associated with ground mount installations characterized by ease of access and fewer equipment requirements, while the higher cost facilities are rooftop mounted that increase the complexity of removal activities. Escalating the estimates to the end of the proposed 20-year average service life results in a total decommissioning estimate of $81 million as shown in Table III-23. Because of limited retirement history, SCE is not proposing recovery of interim retirement net salvage at this time.

Table III-23
Solar Decommissioning Costs by Panel Type ($000's)

Installation Type	2015 $ Megawatt	Installed MW	Total Decomm 2015 ($)	Total Decomm Retirement Year ($)
A	B	C	D=B*C	E
Rooftop - Floating	$614	54	$32,890	$47,959
Rooftop - Anchored	$645	31	$20,071	$29,486
Ground Mount	$354	7	$2,395	$3,410
			$55,355	$80,855

(7) Fuel Cell Net Salvage

SCE is not proposing to recover decommissioning costs for Fuel Cells at this time because of the expectation to transfer ownership to site hosts at the end of their 10-year life.

While SCE is not proposing decommissioning at this time, it is not unreasonable to expect that if circumstances change, there will be future costs to retire these plants.

(8) Energy Storage Net Salvage

SCE is proposing to install lithium-ion battery units in a rack configuration. Engineers indicate that the removal activities to retire these assets include driving to the facility, removing the battery modules the rack, and shipping to recycling centers for disposal. Engineers also indicate that there may be a small amount of gross salvage associated with the recycling of the units. Although it is not unreasonable to assume that there may be increasing costs to retire these assets in the future (*e.g.*, if recycling salvage becomes disposal fees) SCE is not proposing decommissioning costs for energy storage assets at this time.

3. Forecast Service Lives for G&I Assets

Some categories of plant do not lend themselves to statistical analysis, but do not belong in the life span category. These plant assets include most general plant (*i.e.*, FERC Accounts 391-397), intangible plant (*e.g.,* software, radio frequencies, etc.), and easements. SCE determined average service lives through conducting discussions with SCE engineers familiar with the assets, considering prior company procedure, and being familiar with industry practice.

Table III-24, below, shows the forecast depreciation service lives for general and intangible plant accounts. The table compares SCE's proposed depreciation rates to authorized service lives from D.15-11-021 (the 2015 GRC Decision). As discussed in the sections below, because Power Management Systems (Account 391.4) and Telecommunications Equipment (Account 397) consist of sub-accounts of fairly disparate service lives, the subaccounts have been categorized based upon the equipment lives. For example, in the case of Telecommunication Equipment, SCE grouped Telephone Systems with Videoconferencing Equipment in a 7-year category separate from the infrastructure equipment such as open wire communication conductor and antenna support structures that belong in a 40-year category.

Table III-24[67]
General and Intangible Plant Service Life Proposals

Account No.	Account Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
General Plant			
391.1	Office Furniture	20	20
391.2	Personal Computers	5	5
391.3	Mainframe Computers	5	5
391.4	DDSMS-Power Management System	7.8	10.2
391.5	Office Equipment	5	5
391.6	Duplicating Equipment	5	5
391.7	PC Software	5	5
393	Stores Equipment	20	20
394	Tools & Work Equipment	10	10
395	Laboratory Equipment	15	15
397	Telecommunication Equipment	10.3	8.6
398	Misc Power Plant Equipment	20	20
Intangibles			
302.020	Hydro Relicensing	Various	Various
303.640	Radio Frequency	40	40
302.050	Miscellaneous Intangibles	20	20
303.105	Capitalized Software - 5 year	5	5
303.707	Capitalized Software - 7 year	7	7
303.210	Capitalized Software - 10 year	10	10
303.315	Capitalized Software - 15 year	15	15
Easements			
350	Transmission Easements	60	60
360	Distribution Easements	60	60
389	General Easements	60	60

[67] Refer to WP SCE-09 Vol. 03, Book A, pp. 5-12 (Rate Determination Schedule).

4. Forecast Service Lives – Account-By-Account

a) General Plant

Most general and intangible plant accounts contain many low value individual items. Following FERC guidelines, non-structural items in these accounts are amortized by vintage group over the specified service life and retired at the end of the life span.[68] For example, personal computers are amortized over a 5-year period (*i.e.*, a 20 percent annual depreciation rate) and when a vintage group reaches five years of age, the vintage group of computers will be fully depreciated and retired off the books. Following this approach eliminates costly plant record keeping and continuous physical tracking of the equipment. Over time, imbalances in the accumulated depreciation can occur if there are depreciation life or rate changes and if net salvage is recorded to the books but not reflected in the depreciation rate. These accumulated depreciation surpluses (deficits) are amortized over this GRC cycle (2018-2020).

(1) Account 391.1 – Office Furniture

Account 391.1 contains all costs incurred to acquire office furniture. It includes such items as modular furniture, desks, cabinets, and files used for general utility service that are not permanently attached to buildings. A 20-year average service life is reasonable for both modular and free standing furniture.

(2) Account 391.2 And 391.3 – Computer Equipment

The assets in Account 391.2 can include Central Processing Units and associated components (*e.g.*, monitors, printers, etc.) when purchased as a bundled unit, or when any of these items are purchased individually and meet the capitalization threshold. Account 391.3 is where SCE records all investment related to mainframe computer and file server equipment. SCE information technology personnel state that the average life for this equipment should be five years or less. Retention of the five-year life is reasonable.

(3) Account 391.4 – Power Management System

Account 391.4 contains Supervisory Control and Data Acquisition (SCADA) equipment for controlling and monitoring the SCE electrical system. Contained within this

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68 FERC Accounting Release Number AR15 provided for the vintage year accounting method allowing companies to amortize vintage groups of assets over their designated service life and subsequently retire them. The FERC accounting release states that "[a]doption- of vintage year accounting will relieve companies from maintaining extensive plant records and will generate efficiencies and costs savings without degrading the quality of plant records and the associated financial reporting."

account are the components making up the Power Management System specifically, computer and data gathering equipment, man-machine interface, analog and digital telemetry devices, and data center facility infrastructure. The account consists of components with very different lives depending upon the technical sophistication and other retirement factors affecting the equipment. SCE's power management personnel have assessed this equipment as having service lives in categories of 5, 7, 10, 15 or 20 years. A dollar weighting of these equipment lives yields a combined average service life of about 10 years. Each of these equipment life categories are summarized in Table III-25 and addressed in the following discussions.

Table III-25
Power Management System Service Life Proposals

CPR Account	Description	2015-2017 Authorized (Years)	2018-2020 Proposed (Years)
Five-Year Power Management System Equipment			
391.417	Firewall	7	5
391.422	TACACS/Sniffer	10	5
391.405	EMS Web Server	20	5
391.406	EMS Workstation	20	5
391.43	External Tape Drive	20	5
Seven-Year Power Management System Equipment			
391.401	Bulk Storage	7	7
391.416	USAT Hub	7	7
Ten-Year Power Management System Equipment			
391.402	Communications Network Processor	10	10
391.404	Server Cabinet	10	10
391.411	Large Screen Display System	10	10
391.419	Dynamic Map Board	25	10
391.42	Data Acquisition Controller	10	10
391.429	Digital Wall Chart Recorded	10	10
391.435	Dial-Up Remote Terminal Unit	10	10
Fifteen-Year Power Management System Equipment			
391.436	Uninterruptible Power Supply	15	15
391.438	Battery System	15	15
Twenty-Year Power Management System Equipment			
391.421	Remote Terminal Unit (RTU)	20	20

(a) Five-Year Power Management System Equipment

Equipment in the 5-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Due to these changing needs, the hardware asset portfolio will become obsolete if not actively refreshed, which can significantly affect operations. Furthermore, these devices contain components like processors, memory, and rotating disks that become obsolete and/or worn out after five years of continuous use.

(b) Seven-Year Power Management System Equipment

Equipment in the 7-year category is typically modern, digital electronic computer and microprocessor-based equipment which is subject to discontinued support by the manufacturer or replaced with newer equipment within a short period of time. Furthermore, these devices contain rotating disk, printers and CRTs that become obsolete and/or worn out after seven years of continuous use.

(c) Ten-Year Power Management System Equipment

SCE's power management personnel indicate that the ten-year lived equipment is less sophisticated than the typical 7-year items. They contain digital electronics as well as some electromechanical devices. Most of this equipment is specialized, proprietary and generally supported by the vendor for 10 years. Past experience indicates this equipment will be replaced after about 10 years.

(d) Fifteen-Year Power Management System Equipment

Telemetry equipment is analog devices with mostly repairable parts. They do not contain a high degree of sophistication and with proper maintenance, these devices should last approximately 15 years. The Uninterruptible Power System is an electromechanical device with a rated life of about 15 years. Beyond 15 years both of these devices require high levels of maintenance due to passive component failures and electromechanical malfunction.

(e) Twenty-Year Power Management System Equipment

Twenty-year power management system equipment contains hardened substation field equipment used for data gathering. The equipment is highly fault-tolerant and is typically supported by the vendor for approximately 20 years. Also included here are Wall Strip Chart Recorders and Backup Control Systems. These are robust analog devices containing some passive electronics typically rated for 20 years of service.

(4) Account 391.5 and 391.6 – Office Equipment; Duplicating Equipment

These accounts represent a $7.4 million net investment in miscellaneous office equipment such as video projection equipment, public address equipment, plotters, duplicating equipment, and so forth. The current service life of five years is reasonable.

(5) Account 393 – Stores Equipment

Account 393 represents a $7.6 million net investment in equipment used for the receiving, shipping, handling, and storage of materials and supplies for warehouses. It includes electric pallet jacks, lifting tables, stretch wrapping machine, racking rotobins/storage bins, battery chargers, transformer trays, hand-held scanners, lockers, picking carts, awnings, barrel grabbers, warehouse heaters, screen netting, cable cutting machines, and so forth. Based on historical Stores Equipment usage and knowledge of warehouse equipment, the operational personnel state that this equipment has a useful service life of 20 years or less. Retaining the current 20-year service life is reasonable for this account.

(6) Account 394 – Tools & Work Equipment

Account 394 represents a $49.2 million net investment in tools and equipment for construction, repair, maintenance, general shop, and garage, but not specifically includable in other accounts. SCE proposes retaining the current service life of 10 years.

(7) Account 395 – Laboratory Equipment

Account 395 represents a $63.8 million net investment in laboratory and field test equipment. The account has a wide variety of equipment. It includes, for example, calibrators, baths, furnaces, current shunts, dew point meters, gauge calibrators, insulation testers, gas leak detectors, mass comparator, micrometers, multimeters, oscilloscopes, phase meters, watthour meter testing power source, power system analyzers, self-contained portable calibration carts, sound meters, metrology standards, thermometer, vibration analysis data pack, and volt meters. The expected average service life of lab and test equipment is impacted by two major retirement factors: technological obsolescence and normal "wear and tear" from usage in both the field and lab environments. SCE proposes to retain the currently authorized 15-year average service life for this account.

(8) Account 397 – Telecommunication Equipment

Account 397 represents SCE's investment in communication equipment for the company's system. Contained within this account are the electronic and computer-based equipment (such as transmission equipment, dynamic network multiplexers, data network interconnection system, and radio equipment), as well as communication infrastructure (such as the copper and fiber optic cable, conduit, microwave equipment, and the electrical power generator system). SCE telecommunication engineers have assessed this equipment as having service lives of 5, 7, 10, 15, 25, or 40 years depending on the type of equipment.[69] These are the same service lives the Commission authorized in the prior rate case. The equipment lives are addressed in the following discussions.

(a) Five-Year Communication Equipment

Equipment falling into the 5-year category experiences shorter lives from lack of vendor support, facility relocations, and insufficient capacity to meet current demand.

(b) Seven-Year Communication Equipment

Equipment in the 7-year category is typically modern, state-of-the art, electronic and/or computer-based equipment which is subject to being discontinued by manufacturer or replaced with newer equipment within a short period of years.

(c) Ten-Year Communication Equipment

NetComm radio equipment is not as sophisticated as the other electronic equipment and warrants a 10-year service life. SCE is replacing NetComm radios after about 10 years.

(d) Fifteen-Year Communication Equipment

Equipment in this group of assets is typically subject to environmental wear and has an average life of about 15 years. The equipment fails or is replaced as a result of unreliability and/or high maintenance due to failure of passive components or electromechanical failure. In the case of electronic components included in this category, the telecommunication engineers state that these are relatively basic and not the state-of-the art- electronics reflected in the seven-year life category.

(e) Twenty-Five Year Communication Equipment

Although SCE has not yet had fiber optic cable as long as 25 years, SCE telecommunication engineers believe that it may be subject to greater level of degradation than the copper cable. They estimate that 25 years is a reasonable life for the fiber optic cable.

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[69] Refer to WP SCE-09 Vol. 03, Book A, pp. 314-318 (Telecomm. Engineering Data).

(f) Forty-Year Communication Equipment

The balance of the communication infrastructure includes such equipment as overhead and underground communication cable, the communication conduit system, and antenna support structures. This equipment has an average 40-year service life. The items are subject to physical or mechanical deterioration since they are subject to outdoor environments.

(9) Account 398 – Miscellaneous

Account 398 represents a $21.8 million net investment in miscellaneous utility equipment that does not fit other plant accounts. Examples can include such diverse items as kitchen and infirmary equipment. The current service life of 20 years is a reasonable depreciation period for this account.

b) Intangibles

SCE has investments in a number of intangible assets, including hydro relicensing, radio frequencies, long term franchise fees, capitalized software, and land easements and rights-of-way. As previously discussed, the hydro relicensing costs are amortized over the remaining life of the FERC project license period. SCE proposes to continue amortizing the radio frequency investments over the 40-year service life and land easements and rights-of-way over the 60 year service life determined in prior rate case proceedings. The other categories are discussed below.

(1) Miscellaneous Intangibles

The year-end 2015 net investment for miscellaneous intangibles is approximately $431 thousand, which is largely made up of long-term franchise costs (~$300 thousand). SCE proposes to allocate these costs over 20 years.

(2) Capitalized Software

The depreciable life of capitalized software reflects the estimated life prior to investments required to replace or optimize the software as a result of technology, vendor, or business obsolescence. SCE proposes to continue the four existing service life categories of five, seven, ten, and fifteen years determined in prior proceedings.

(3) Easements

SCE proposes to retain the authorized amortization period of 60 years for its easements and rights-of-way.

Appendix A

2016 Service-Life and Net Salvage Study

2016 Service–life and Net Salvage Study

SOUTHERN CALIFORNIA EDISON

An *EDISON INTERNATIONAL* Company

foster associates

CONTENTS

August 2016

EXECUTIVE SUMMARY

INTRODUCTION

This report presents a study and recommended service–life statistics and future net salvage rates for transmission, distribution and general depreciable plant owned and operated by Southern California Edison Company (SCE). Foster Associates was engaged by SCE in January 2016. The study was completed in July, 2016.

Foster Associates is a public utility economics consulting firm offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by the firm's Fort Myers office include property life forecasting, technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer software for conducting depreciation and valuation studies.

Depreciation rates currently used by SCE were approved by the California Public Utilities Commission (CPUC) in D.15–11–021, dated November 5, 2015. The approved rates were derived from a study conducted on December 31, 2012 plant and depreciation reserve balances. Findings and recommendations developed in the current study are summarized in Section III of this report.

SCOPE OF STUDY

The principal activities undertaken in the course of the current study included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Field visits and discussions with SCE operations and plant accounting personnel;
- Statistical life studies and estimation of projection lives and projection curves; and
- Per unit and moving average net salvage studies and estimation of future net salvage rates.

STUDY PROCEDURE

INTRODUCTION

The purpose of a comprehensive depreciation study for a regulated utility is to analyze the mortality characteristics, net salvage rates and the adequacy of depreciation accruals derived from currently approved depreciation rates. The findings from such an investigation are used in the formulation of revised depreciation rates subject to regulatory approvals.

In the case of the current study, Foster Associates was engaged by SCE to only study and recommend service–life statistics and future net salvage rates in compliance with CPUC directives in D.15–11–021. SCE would then incorporate the recommendations in depreciation rates developed by the Company.

Regarding the directives in D.15–11–021, the CPUC directed SCE to provide full explanations of the quantitative or qualitative base for the application of judgment in future depreciation showings. The Commission further directed the Company to provide:

1. A quantitative discussion of historical and future COR on a per unit basis for the large (greater than 15% as measured by the portion of plant balance) asset classes in the account. This should identify and explain the key factors in changing or maintaining the per–unit COR.
2. Quantitative discussion of historical and future retirement mix; identifying and explaining the key factors in changing or maintaining this mix.
3. Quantitative discussion of asset life and original cost of assets being retired, in relation to the COR, on both a historical and prospective basis. This discussion should be integrated with and/or cross–reference the proposal for life characteristics.
4. An account–specific discussion of the process for allocating costs to COR.

SCOPE

The steps involved in conducting the depreciation study can be grouped into three major tasks:

- Data Collection;
- Life Analysis and Estimation; and
- Net Salvage Analysis and Estimation.

The scope of the 2016 service–life and net salvage study included a consideration of each of these tasks as described below.

DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi–actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by SCE provides aged transactions for all plant accounts.

Service life statistics estimated in the 2016 study were derived from plant accounting transactions recorded over the period 2002 through 2015. Detailed accounting transactions were extracted from the Continuing Property Record (CPR) system and assigned transaction codes which describe the nature of the accounting activity. Transaction codes for plant additions, for example, were used to distinguish normal additions from acquisitions, purchases, reimbursements and adjustments. Similar transaction codes were used to distinguish normal retirements from sales, reimbursements, abnormal retirements and adjustments. Transaction codes were also assigned to transfers, capital leases, gross salvage, cost of removal and other accounting activity that should be considered in a depreciation study.

The accuracy and completeness of the assembled database was verified for activity years 2002 through 2015 by comparing the beginning plant balance, additions, retirements, transfers and adjustments, and the ending plant balance derived for each activity year to the official plant records of the Company. Age distributions of surviving plant at December 31, 2015 were reconciled to the CPR.

LIFE ANALYSIS AND ESTIMATION

Life analysis and life estimation are terms used to describe a two–step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. The mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

It is important to note what is being estimated in a service life study. It is not unit-years of service; it is dollar–years of service. Retirements are not recorded for plant accounting purposes in units such as feet, pounds, segments or any similar physical measurement. Plant records are maintained in dollars and service lives are measured in dollar–years of service. Estimating service lives based on engineering studies of how long, on average, units of property might remain in service is not equivalent to estimating dollar–years of service.

The size of a retirement unit also matters. A company that defines a span of conductor between supports to be a retirement unit will measure longer service lives than a company that defines one foot of conductor as a retirement unit. Replacement of conductor less than a retirement unit is charged to operating expense and no retirement is recorded for the replaced unit. Larger units result in less frequent recorded retirements, which translate to longer average dollar–years of service.

An added dimension of complexity is introduced when retirements occur at varying ages, attributable to mixed forces of retirement. This creates a non-homogeneous account composed of two subpopulations acted upon by differing forces of retirement. The estimated projection life for such an account measured in dollar–years of service will converge toward the mean of the subpopulation most resistant to the forces of retirement.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered descriptive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi–actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each property unit must be identifiable by date of installation and age at retirement. Semi–actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available. Age identification of retirements over the period 2002–2015 was available for all plant accounts included in the 2016 study.

An actuarial life analysis program designed and developed by Foster Associates was used in this study. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age–intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age–interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual–rate or retirement–rate method was used in this study. The mechanics of the annual–rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This so–called "retirement ratio" (or set of ratios) is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual–rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this study are the Iowa–type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least–squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life for each plant account. The smoothed survivorship function was then fitted by a weighted least–squares procedure to the Iowa–curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this analysis provides multiple rolling–band, shrinking–band and progressive–band analyses of an account. Observation bands are defined in terms of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling–band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking–band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive–band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the Foster Associates actuarial life analysis program include: the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides tabular and graphics output as an aid in the analysis.

While actuarial and semi–actuarial statistical methods are well suited to an analysis of plant categories containing a large number of homogeneous units (*e.g.*, poles and conductors), the concept of retirement dispersion is interpreted differently for plant categories composed of major items of plant that will most likely be retired as a single unit. Plant retirements from an integrated system prior to the retirement of the entire facility are more properly viewed as interim retirements that will be replaced in order to maintain the integrity of the system. Additionally, plant facilities may be added to the existing system (*i.e.*, interim additions) in order to expand or enhance its productive capacity without extending the service life of the existing system. A proper depreciation rate can be developed for an integrated system using a life–span method. All depreciable plant accounts classified in transmission, distribution and general were studied as full mortality categories in the 2016 study.

NET SALVAGE ANALYSIS

Depreciation rates designed to achieve the goals and objectives of depreciation accounting will include a parameter for future net salvage and a variable for average net salvage reflecting both realized and future net salvage rates.

Estimates of net salvage rates applicable to future retirements are most often derived from an analysis of gross salvage and cost of removal realized in the past. An analysis of past experience (including an examination of trends over time) provides a reasonable basis for estimating future salvage and cost of removal. However, consideration should also be given to events that may cause deviations from net salvage realized in the past. Among the factors that should be considered are: the age of plant retirements; the portion of retirements likely to be reused; changes in the method of removing plant; the type of plant to be retired in the future; inflation expectations; the shape of the projection life curve; and economic conditions that may warrant greater or lesser weight to be given to net salvage rates observed in the past.

Average net salvage rates for an account or plant function are derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements *(i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

Special consideration should also be given to the treatment of insurance proceeds and other forms of third–party reimbursements credited to the depreciation reserve. A properly conducted net salvage study will exclude such activity from the estimate of future parameters and include the activity in the computation of realized and average net salvage rates.

A five–year moving average analysis of the ratio of realized salvage and removal expense to the associated retirements was conducted in the 2016 study for transmission, distribution and general plant categories to aid in: a) estimating a realized net salvage rate; b) detecting the emergence of historical trends; and c) establishing a basis for estimating a future net salvage rate. Cost of removal and salvage opinions obtained from Company personnel were also considered in the estimation of future net salvage rates.

In compliance with the CPUC directive in D.15–11–021, per unit net salvage analyses were conducted for the nine (9) plant accounts listed in Table 1 below.

Account Description
354.00 Towers and Fixtures
355.00 Poles and Fixtures
356.00 Overhead Conductors and Devices
364.00 Poles, Towers and Fixtures
365.00 Overhead Conductors and Devices
366.00 Underground Conduit
367.00 Underground Conductors and Devices
368.00 Line Transformers
369.00 Services

Table 1. Per Unit Net Salvage Accounts

Each of the nine plant accounts was grouped into one or more subpopulations of major equipment categories. Historical per unit ratios (defined as net cost per unit to retire divided by the cost per unit to install) were used in both a historical and future per unit analyses. Net costs to retire (or net salvage) were used in the analysis to maintain consistency with future net salvage parameters used in the formulation of remaining–life accrual rates.

Future per unit ratios were derived using an average of the subpopulation net salvage per unit values recorded over the period 2009–2015. These values appear in the numerator of future per unit ratios.

The per unit cost of plant additions used in forecasting future net salvage rates was obtained by dividing vintaged plant in service at December 31, 2015 (*i.e.*, age distributions of surviving plant) by vintaged units in service within each subpopulation. The ratio of average net salvage per unit experienced over the period 2009–2015 (adjusted for inflation) to the per unit cost of plant in service is the ratio that was applied to forecasted retirements to estimate future net salvage for each vintage. The sum of future net salvage over all vintages divided by current plant account balances produces an estimated future net salvage rate for each primary account.

RECOMMENDATIONS AND ANALYSIS

RECOMMENDATIONS

Table 2 below provides a summary of current and recommended projection lives, projection curves and future net salvage rates estimated for SCE in the 2016 study.

Account Description	Current			Recommended		
	P-Life	Dispersion	Sf %	P-Life	Dispersion	Sf %
A	C	D	E	F	G	H
Transmission Plant						
352.00 Structures and Improvements	55.00	S3	-35.0	55.00	L1	-35.0
353.00 Station Equipment	45.00	R0.5	-15.0	40.00	L0.5	-10.0
354.00 Towers and Fixtures	65.00	R5	-60.0	65.00	R5	-185.0
355.00 Poles and Fixtures	50.00	R0.5	-72.0	65.00	SC	-499.0
356.00 Overhead Conductors and Devices	61.00	R3	-80.0	61.00	R3	-210.0
357.00 Underground Conduit	55.00	R3	0.0	55.00	R3	0.0
358.00 Underground Conductors and Devices	40.00	R2.5	-15.0	45.00	S1	-25.0
359.00 Roads and Trails	60.00	SQ	0.0	60.00	R5	0.0
Distribution Plant						
361.00 Structures and Improvements	42.00	R2.5	-25.0	50.00	L0.5	-30.0
362.00 Station Equipment	45.00	R1.5	-25.0	65.00	L0.5	-50.0
364.00 Poles, Towers and Fixtures	47.00	L0.5	-210.0	55.00	R1	-488.0
365.00 Overhead Conductors and Devices	45.00	R0.5	-115.0	55.00	R0.5	-538.0
366.00 Underground Conduit	59.00	R3	-30.0	59.00	R3	-401.0
367.00 Underground Conductors and Devices	45.00	R0.5	-60.0	43.00	R1.5	-261.0
368.00 Line Transformers	33.00	R1	-20.0	33.00	S1.5	-47.0
369.00 Services	45.00	R1.5	-100.0	45.00	R1.5	-387.0
370.00 Meters	20.00	R3	-5.0	20.00	R3	0.0
373.00 Street Lighting and Signal Systems	40.00	L0.5	-30.0	48.00	L1	-100.0
General Plant						
390.00 Structures and Improvements	38.00	R3	-5.0	45.00	R0.5	-10.0

Table 2. Service Life and Net Salvage Parameters

ANALYSIS

A description of each account examined in the 2016 study and factors considered in the estimation of recommended service life and net salvage parameters is contained in the following pages of this report.

TRANSMISSION PLANT
ACCOUNT: 352.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in structures and improvements used in connection with transmission operations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	55-S3	55-L1
Future NS Rate	-35.0%	-35.0%
Realized NS	-13.3%	
Average Age (yrs.)	8.6	
Derived Additions	$717,577,812	
Plant Retirements	$30,750,408	
Percent Retired	4.5%	
Plant Balance	$686,827,404	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

The statistical service life indications for the full account are derived from unlikely recurring retirement activity. Retirements of $22.9M reported in 2009, constituting 75 percent of the total retirements over the 14–year study period, were related to the retirement of equipment at the Sylmar substation. Average service life indications from the statistical service life analysis range from the low 30s to the mid–50s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each subpopulation are shown in Table 2 below.

The variability of subpopulation service lives is an indication of a nonhomogeneous plant account with mixed forces of retirement acting on the subpopulations. Heterogeneity coupled with high degrees of censoring reduces the level of confidence that can be placed in service–life indications obtained from either a subpopulation or total account analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Foundations	178,220,072	26	85-L1	38.5
MEER Building	159,486,338	23	130-R0.5	73.4
Water Supply	107,675,420	16	103-R3	82.8
Alarm & Monitoring	45,931,434	7	194-S6	99.4
Power Lighting	30,490,714	4	107-L0.5	71.9
HVAC	12,046,998	2	38-L0	7.7
Non-unitized	120,611,640	18		
Miscellaneous	32,364,788	5	30-L0.5	3.7
Total	686,827,404	100	107	

Table 2. Major Structural Components

LIFE ESTIMATION

Based mainly on the first–degree statistical service–life indications, thereby rejecting origin–modal dispersions in which chance is a more pervasive force of retirement, a 55–L1 projection life–curve is recommended for this account. This recommendation retains the currently approved projection life and adjusts the projection curve to reflect lower modal curves observed in the subpopulation analysis. The recommendation also reflects a lack of evidence for adjusting the service life estimates given the single retirement underlying a significant percentage of the retirement history. Foster Associates was informed that Company engineers and operations personnel do not anticipate policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account exhibits an overall realized net salvage rate of –13.3 percent from $31M of retirement activity over the period 2002–2015. More recent 5–year moving average bands indicate realized negative net salvage exceeding –87 percent.

NET SALVAGE ESTIMATION

Based on this historical experience and the expectation of continuing removal costs when these facilities are retired, retention of a –35 percent future net salvage rate is recommended for consideration by SCE. As in the service life estimation, this recommendation reflects lack of evidence for adjusting future net salvage estimates given the single retirement underlying a significant percentage of the retirement history in this account.

TRANSMISSION PLANT
ACCOUNT: 353.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the cost in transforming, conversion, and switching equipment used for the purpose of changing the characteristics of electricity in connection with its transmission or for controlling transmission circuits. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	40-L0.5
Future NS Rate	-15.0%	-10.0%
Realized NS	0.6%	
Average Age (yrs.)	10.3	
Derived Additions	$5,785,827,668	
Plant Retirements	$538,115,861	
Percent Retired	10.3%	
Plant Balance	$5,247,711,807	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Retirement activity in transmission station equipment is largely associated with age, obsolescence and growing or shifting loads that necessitate rebuilding to larger capacities. Company engineers report that thermal, mechanical, and electrical integrity issues intensify with age typically beginning around age 30 years when insulation degradation, increased in–service failures, and increased maintenance arises. Retirements occur when increased costs and decreased utilization rates dictate is it no longer economic to repair such equipment. Decreased spare parts availability as equipment ages also plays a major role in age–related retirements.

The Company utilizes a Condition Based Maintenance (CBM) approach to manage all transformers and circuit breakers by routinely conducting off–line diagnostics, visual inspections, and functional checks. These analysis components are combined with other key data such as age, design, moisture levels, loading, and fault exposure to develop a health index ranking that is maintained throughout the life of these assets and used in the determination of when to repair or retire.

Average service life indications from the statistical analysis of the full account range from the low 30s to the low–40s for bands with lower censoring and conformance indexes. The majority of second– and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve	Censoring (%)
Transformers	1,068,594,714	20	41-SC	7.6
Circuit Breakers	631,804,488	12	32-L1.5	0.8
Switches & Switch Gear	520,013,661	10	34-L0	10.4
Control & Monitoring Devices	478,204,337	9	50-L0	-
Bus Support Structures	439,776,382	8	63-R0.5	27.5
Capacitors	309,258,912	6	49-L1	0.6
Power Control Cable	267,340,154	5	51-SC	30.6
Foundations	151,926,940	3	70-L1	34.5
Non-unitized	790,758,849	15		
Miscellaneous	590,033,371	11	36-L0.5	11.2
Total	5,247,711,807	100	44	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience exhibits a range of average service lives between 32 and 63 years with a direct–dollar–weighted average of 44 years and a preponderance of lower–left modal dispersions. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of these subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on indications from both the full account and subpopulation statistical service life analyses, a 40–L0 projection life–curve is recommended for this account. This recommendation is derived from account total service lives indicated for trials with lower censoring, conformance indexes, and hazard functions uncompromised by declining or negative hazard rates. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –12.7 percent, a composite of an 8.2 percent gross salvage rate and a 20.9 percent cost of retiring rate. The most recent 5–year rolling average indicates a –26.4 percent realized net salvage rate.

NET SALVAGE ESTIMATION

Minimal gross salvage, generally from scrap metal and recycling, is expected from the retirement of this equipment. Significant cost of retiring, however, is expected in the form of labor and equipment such as cranes. The adjusted historical net salvage experience provides the basis for recommending a –10 percent future net salvage rate for consideration by SCE. This recommendation reflects discounting indications obtained from small retirements and large cost of removal recorded in 2015 and focusing more on activity years 2009−2014. The –12.7 realized net salvage rate and –26.4 percent realized net salvage rate observed for the most recent 5–year rolling band are somewhat distorted by the 2015 activity, which is not considered indicative of future expectations.

TRANSMISSION PLANT
ACCOUNT: 354.00 – TOWERS AND FIXTURES

DESCRIPTION

This account includes the cost installed of towers and appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	65-R5	65-R5
Future NS Rate	-60.0%	-185.0%
Realized NS	-799.7%	
Average Age (yrs.)	9.3	
Derived Additions	$2,264,446,057	
Plant Retirements	$4,473,231	
Percent Retired	0.2%	
Plant Balance	$2,259,972,826	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission towers and fixtures include line upgrades, corrosion, relocation (for lower voltage structures), and failures due to wind storms, ice, or floods. Most of these forces tend to increase with age. Although storm damage can generally be expected to impact retirements at any age, in combination with deterioration, the probability of failure is cumulative. SCE performs annual inspections on all transmission towers and performs subsequent maintenance identified from those inspections.

The statistical service life indications for the full account are derived from minimal and irregular retirement activity. Retirements recorded in this account amount to only $4.5M from an average plant balance exceeding $1.3B over the study period and less than 0.2 percent of derived additions. Statistical service life indications derived from this minimal experience are highly censored, unrealistically long (approaching 200 years), and contrary to Company expectations of the future age of tower retirements.

The distribution of major categories of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Towers	1,139,621,027	50	132-S2	71.6
Non-unitized	1,018,898,065	45		
Other	101,453,734	4	178-R2.5	82.2
Total	2,259,972,826	100	136	

Table 2. Major Structural Components

The subpopulation analysis is also highly censored and does not produce interpretative life indications. The account could not be reasonably sub–divided into more than three subpopulations with miscellaneous items constituting only four percent and non–unitized items constituting 45 percent of the investment.

LIFE ESTIMATION

The minimal retirement activity and resulting unreliable service life indications from both the full account and subpopulation statistical analyses do not provide a strong foundation for service–life estimation. Foster Associates, therefore, deferred to SCE in recommending the currently approved 65–R5 projection life–curve. Factors evaluated by SCE beyond the service–life analyses include operational, accounting and ratemaking considerations.

NET SALVAGE ANALYSIS

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –799.7 percent realized from $4.5M of retirements recorded over the period 2002–2015. However, as noted above, total retirements are less than 0.2% of derived additions.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –104 and –185 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Although minimal gross salvage, generally from scrap, is expected from these assets, significant costs of retiring and removing (attributable to labor costs and cost of equipment such as cranes used in the retirement process) are expected to be incurred in the future. Based on the above analysis, a future net salvage rate of −185 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 355.00 – POLES AND FIXTURES

DESCRIPTION

This account includes the installed cost of transmission line poles, wood, steel, concrete, or other material, together with appurtenant fixtures used for supporting overhead transmission conductors. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	50-R0.5	65-SC
Future NS Rate	-72.0%	-499.0%
Realized NS	-155.5%	
Average Age (yrs.)	10.1	
Derived Additions	$1,073,636,145	
Plant Retirements	$65,068,786	
Percent Retired	6.5%	
Plant Balance	$1,008,567,359	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

Major forces of retirement acting upon transmission wood poles include external, internal, top rot, and split top deterioration. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

Indications from the statistical service life analysis for this account range from the mid–60s to the low–80s for bands with lower censoring and conformance indexes. The majority of third–degree polynomial indications are considered less reliable than first–degree or second–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Eng. Light Duty Steel, Concrete	419,049,403	42	84-L0.5	57.2
Wood/Fiberglass/Composite	375,781,560	37	57-SC	29.6
Non-Unitized	212,474,639	21		
Other	1,261,756	0	46-S4	53.5
Total	1,008,567,359	100	71	

Table 2. Major Structural Components

The subpopulation analysis indicates service lives ranging between 46 and 84 years with an average of 71 years. It is the opinion of Foster Associates that service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on the first–degree and second–degree indications of the full account analysis and observations from the subpopulation analysis, a 65–SC projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall realized net salvage rate of –155.5 percent and a –242.5 percent rate for the most recent five–year rolling band. Five–year rolling bands indicate negative net salvage rates exceeding –100 percent for 8 of the 11 analyzed bands.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –90 and –499 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −499 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 356.00 – OVERHEAD CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of overhead conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	61-R3	61-R3
Future NS Rate	-80.0%	-210.0%
Realized NS	-284.3%	
Average Age (yrs.)	13.7	
Derived Additions	$1,500,210,639	
Plant Retirements	$18,103,015	
Percent Retired	1.2%	
Plant Balance	$1,482,107,624	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Forces of retirement acting upon transmission conductors include deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, failure of splices or dead–ends, relocation (*e.g.*, highway widening, damsite construction, etc.), circuit upgrades, system reconfiguration and idle facilities (*e.g.*, closure of generation facilities or loss of large customers).

The statistical service life analysis for this account indicates average service lives exceeding 85 years. The analysis, however, is based on $18M of retirement activity from derived additions exceeding $1.5B. Retirement activity of 1.2 percent of derived additions is not considered sufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 is shown in Table 2. More than 40 percent of the classified investment is conductor larger than 1500 MCM. Service life indications obtained from a full–band statistical analysis of the major categories are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conductor > 220 kV	739,015,019	50	106-R3	57.7
Conductor < 220 kV	202,769,129	14	82-R1.5	84.0
Switches	27,761,688	2	39-R1	2.5
Non-Unitized	399,410,246	27		
Other	113,151,541	8	199-SQ	100.0
Total	1,482,107,623	100	110	

Table 2. Major Structural Components

The subpopulation analysis of the full historical experience evidences a range of average service lives between 39 and 199 years with a dollar–weighted average of 110 years. These indications are compromised by high censoring and minimal retirement activity comparable to observations in the full account.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting extremes in service life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 61–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –284.3 percent. However, as noted above, this history is based on relatively minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –114 and –210 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −210 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

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TRANSMISSION PLANT
ACCOUNT: 357.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing transmission cables or wires. Account statistics and current and proposed parameters are shown in Table 1.

	Current	Proposed
Plife-Curve	55-R3	55-R3
Future NS Rate	0.0%	0.0%
Realized NS	-69.5%	
Average Age (yrs.)	15.6	
Derived Additions	$61,474,359	
Plant Retirements	$387,297	
Percent Retired	0.6%	
Plant Balance	$61,087,062	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Rebuild and digging are the major forces of retirement expected to affect this account. The statistical service–life analysis for the full account is based on highly censored trials (87 percent) with life indications ranging between 88 and 146 years. Only $387,297 or 0.6% of derived additions has been retired from the account.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve	Censoring (%)
Conduit	34,334,761	56	130-S1.5	86.3
Manholes and Vaults	17,239,213	28	65-S2	81.1
Trenches	2,063,079	3		N/A
Non-unitized	7,410,219	12		
Other	39,791	0		N/A
Total	61,087,062	100	108	

Table 2. Major Structural Components

full–band statistical analysis of each category are shown in Table 2 below.

Subpopulation service life indications are similarly derived from highly censored trials providing little insight into future live expectancies.

LIFE ESTIMATION

Neither the full account nor the subpopulation analysis is considered to provide sufficient evidence to support adjusting the currently approved 55–R3 projection life and curve. Current parameters are, therefore, recommended to be retained for this account.

NET SALVAGE ANALYSIS

The adjusted net salvage analysis for this account indicates an overall net salvage rate of –69.5% percent realized from minimal retirement activity of only $387,297.

NET SALVAGE ESTIMATION

The historical net salvage experience is considered insufficient to support an adjustment to the currently approved zero percent future net salvage rate. The current rate is, therefore, recommended for consideration by SCE.

TRANSMISSION PLANT
ACCOUNT: 358.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for transmission purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-R2.5	45-S1
Future NS Rate	-15.0%	-25.0%
Realized NS	-27.0%	
Average Age (yrs.)	11.6	
Derived Additions	$284,995,149	
Plant Retirements	$16,382,826	
Percent Retired	6.1%	
Plant Balance	$268,612,323	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Deterioration, failure, relocations, upgrades and accidental dig–ins are the major forces of retirement acting upon underground conductors. The statistical life analysis conducted for this account indicates average service lives between the mid–30s and mid–40s for trials with lower censoring, conformance indexes, and non–negative retirement ratios.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conductor	163,955,728	61	45-S1.5	51.1
Potheads	27,568,689	10	29-S2	5.2
Arresters	19,845,390	7	31-S1.5	2.0
Cathodic Protection	12,086,839	4	39-R1	81.4
Non-unitized	45,155,677	17		
Total	268,612,323	100	41	

Table 2. Major Structural Components

An analysis of the subpopulations indicates a range of service lives between 29 and 45 years with lower modal dispersions and an average of 41 years. Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–S1 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –27 percent realized from $16M of retirement activity over the period 2002–2015. Five–year rolling bands are relatively stable and range between –14.4 and –49.7 percent. The most recent 5–year rolling band indicates a realized average net salvage rate of –30.6 percent.

NET SALVAGE ESTIMATION

Based on the analysis observations, a –25 percent future net salvage rate is recommended for consideration by SCE. Consideration was given in this recommendation to both the –27 historical average realized net salvage rate and the likelihood of more negative future net salvage given recent experience such as the –30.6 percent realized net salvage rate observed for the most recent 5–year rolling band.

TRANSMISSION PLANT
ACCOUNT: 359.00 – ROADS AND TRAILS

DESCRIPTION

This account includes the cost of roads, trails, and bridges used primarily as transmission facilities. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	60-SQ	60-R5
Future NS Rate	0.0%	0.0%
Realized NS	-314.1%	
Average Age (yrs.)	5.1	
Derived Additions	$194,172,555	
Plant Retirements	$154,514	
Percent Retired	0.1%	
Plant Balance	$194,018,041	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The statistical service life analysis for this account is based on minimal retirement activity of $154,514, or 0.1 percent of derived additions from an average plant balance exceeding $108M over the period 2002–2015. Retirements were reported in only 3 years during that period. The service life analysis is highly censored at more than 76.8 percent with resulting life indications ranging between 95 and 175 years.

LIFE ESTIMATION

Statistical service life indications for this account are considered insufficient to warrant an adjustment to the currently approved projection life. The current SQ projection curve, however, is considered extreme given the historical experience and the likelihood of more dispersed retirements. Based on these observations and considerations, a 60–R5 projection life–curve is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates a realized net salvage rate of –314.1 percent from retirements recorded in 2010, 2012, and 2013 only.

NET SALVAGE ESTIMATION

The underlying retirement experience in the historical net salvage analysis is not considered sufficient to warrant adjusting the currently approved zero percent future net salvage. Retention of the current rate is, therefore, recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 361.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in place of structures and improvements used in connection with distribution operations. The account comprises mainly control houses and related structures at distributions substations. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	42-R2.5	50-L0.5
Future NS Rate	-25.0%	-30.0%
Realized NS	-33.1%	
Average Age (yrs.)	13.8	
Derived Additions	$632,396,471	
Plant Retirements	$55,690,492	
Percent Retired	9.7%	
Plant Balance	$576,705,979	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Major forces of retirement for this account include system upgrades, severe storms and earthquakes, traffic and fire accidents, rodent damage, automation, revisions in policy, code, and criteria, and wear and tear related to aging.

Statistical service life indications for this account range from the low–40s to low–60s for bands with lower censoring and conformance indexes. The majority of second and third–degree polynomial indications are considered less reliable than first–degree polynomial indications. Graduated hazard rates in these instances are unrealistically declining and may be zeroed to remove negative hazard rates implied by the fitted polynomials.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Foundation etc.	112,919,451	20	28-S4	76.6
MEER Building	102,746,634	18	38-S1.5	80.8
Water Supply	50,908,790	9	41-S1.5	74.6
Power Lighting	45,421,111	8	39-S3	92.0
HVAC	33,804,236	6	35-R2	72.5
Alarm & Monitoring	16,557,229	3	29-S3	84.1
Non-unitized	39,863,694	7		
Other	174,484,836	30	60-O3	29.4
Total	576,705,980	100	43	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives ranging between 29 and 60 years, various dispersions, and a dollar–weighted mean of 43 years.

LIFE ESTIMATION

Based on these observations and ignoring origin–modal dispersions in which chance is a more pervasive force of retirement, a 50–L0.5 projection life–curve is recommended for this account.

Service–life indications derived from a statistical analysis of the combined subpopulations are well within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category. Company operations personnel do not expect policy or procedural changes or technological advances that would introduce significantly different forces of retirement from those observed in the past.

NET SALVAGE ANALYSIS

The historical net salvage analysis for this account indicates an adjusted overall net salvage rate of –33.1 percent realized from $55,690,492 of retirement activity over the period 2002–2015. Five–year rolling band rates have not been less negative than –21.3 percent during that period and the five–year band ending in in 2015 shows a –44.2 percent net salvage rate.

NET SALVAGE ESTIMATION

Based on these observations and considerations, a –30 percent future net salvage rate is recommended for consideration by SCE. It is considered unlikely that the upward trend in cost of removal will reverse in the near future.

DISTRIBUTION PLANT
ACCOUNT: 362.00 – STATION EQUIPMENT

DESCRIPTION

This account includes the installed cost of station equipment, including transformer banks, used for the purpose of changing the characteristics of electricity in connection with its distribution. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	65-L0.5
Future NS Rate	-25.0%	-50.0%
Realized NS	-46.5%	
Average Age (yrs.)	13.1	
Derived Additions	$2,382,404,227	
Plant Retirements	$138,133,698	
Percent Retired	6.2%	
Plant Balance	$2,244,270,529	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The statistical service life analysis for this account indicates average service lives within a narrow range between the mid–50s and mid–60s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Transformers	359,814,116	16	56-L1	81.9
Monitoring Devices	275,879,081	12	34-R2	61.6
Circuit Breakers	270,107,330	12	45-S0.5	81.3
Bus Support	182,345,026	8	75-L0.5	90.1
Power Control Cable	115,539,624	5	42-L1	75.7
Switches	95,098,077	4	52-L1	81.7
Non-unitized	394,553,141	18		
Other	550,934,134	25	64-L0.5	19.7
Total	2,244,270,528	100	54	

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 34 and 75 years with lower modal dispersions and a dollar–weighted mean of 54 years.

Service–life indications derived from a statistical analysis of the combined sub-populations are well within a zone of reasonableness when compared to the sub-population indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 65–L0.5 projection life–curve is recommended for this account. This recommendation is within the range of both full account and subpopulation service life indications. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to wear–out of about 37 years for A–Bank (200 kV) transformers and about 57 years for B–Bank (115 or 66 kV) transformers. The number of transformers in service at year–end 2015 was 158 A–Bank and 2,226 B–Bank. Company engineers also estimate that the mean time to wear–out of mainline and radial oil switches is about 35 years and about 49 years for circuit breakers. The average age of transformers measured in unit−years is about 26 years whereas the average age measured in dollar–years is about 10 years. Similarly, the average age of circuit breakers measured in unit−years is about 32 years whereas the average age measured in dollar–years is about 10 years.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.5 percent, realized from $138,133,698 of retirement activity and 5.8 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit net salvage rates of –47.2, –65.6 and –81.4 percent respectively.

NET SALVAGE ESTIMATION

Based on these observations and the expectation of continuing negative net salvage, a –50 percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 364.00 – POLES, TOWERS AND FIXTURES

DESCRIPTION

This account includes the installed cost of poles, towers, and related fixtures used for supporting overhead distribution conductors and service wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	47-L0.5	55-R1
Future NS Rate	-210.0%	-488.0%
Realized NS	-505.0%	
Average Age (yrs.)	11.3	
Derived Additions	$2,608,099,972	
Plant Retirements	$144,713,616	
Percent Retired	5.9%	
Plant Balance	$2,463,386,356	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of wood poles in the Company's system are full–length and "through–boring" treated to protect against decay and insect attack. Wood poles may also be treated with a steel stub or a fiberglass wrap to provide additional support. In addition to pole treatment, the Company conducts a 10–year inspection cycle to address safety and reliability. Tree trimming and vegetation management are also a significant component of reliability measures undertaken by the Company.

As with transmission wood poles, major forces of retirement acting upon distribution wood poles include external, internal, top rot, split top deterioration and pole loading. Additional forces include vehicles, wind, storm, fire, and bird (mainly woodpecker) damage. Response to these forces partly depends on the specific locale of the pole given the Company's wide geographical area encompassing mainly desert but also agricultural, rural, and urban communities.

The statistical service life analysis for this account indicates consistent indications with average service lives around the mid–50s for bands with lower censoring and conformance indexes.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the single subpopulation of poles indicates a 53–R1 projection life–curve at 46 percent censoring. This indication is comparable to indications obtained for the full band statistical service life analysis.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	2,191,572,261	89	53-R1	46.0
Non-unitized	271,814,095	11		
Total	2,463,386,356	100	53	

Table 2. Major Structural Components

LIFE ESTIMATION

Based on these indications of a slightly longer projection life than currently approved, a 55–R1 projection life–curve is recommended for this account.

NET SALVAGE

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –505.0 percent, realized from $144.7M of retirement activity constituting 5.5 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 exhibit negative net salvage rates exceeding –600 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –180 and –488 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −488 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 365.00 – OVERHEAD CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the cost installed of overhead conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	55-R0.5
Future NS Rate	-115.0%	-538.0%
Realized NS	-206.4%	
Average Age (yrs.)	16.7	
Derived Additions	$1,571,387,374	
Plant Retirements	$138,400,064	
Percent Retired	9.7%	
Plant Balance	$1,432,987,310	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Rebuild programs and relocation to address changes in capacity and rights of way, deterioration resulting from atmospheric corrosion, fatigue failure due to conductor vibration, storm damage, and splice failure are the major forces of retirement acting upon this plant category. Lightning strikes also nick the conductor, reducing its capacity and eventually causing burndown. Although repair at the damaged point is possible with splicing and reconnecting, it is costly. It is common, therefore, to remove and replace a longer section of the damaged conductor, which is usually the span between supports. Overhead to underground facilities conversion, such as that governed by CPUC Rule 20, continues to be a force of retirement acting upon this account.

The statistical service life analysis for this account is based on moderately censored trials with censoring exceeding 47 percent. A number of first and second–degree polynomials indications derived from graduated hazard rates that are unrealistically declining or zeroed were rejected. Origin–modal dispersions in which chance is a more pervasive force of retirement were also rejected. More consistent indications for bands with lower censoring and conformance indexes indicated average service lives between 36 and 65 years and lower modal dispersions.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below. Equipment classified in the "Other" category includes primarily circuit breakers and fuse holders.

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Overhead Conductor	946,696,334	66	70-R0.5	65.3
Switches	347,104,388	24	42-S0	26.7
Non-unitized	52,173,406	4		
Other	87,013,183	6	24-O3	3.8
Total	1,432,987,311	100	60	

Table 2. Major Structural Components

An analysis of the subpopulations indicates service lives between 24 and 70 years with lower modal dispersions and a dollar–weighted average of 60 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 55–R0.5 projection life–curve is recommended for this account based upon the more consistent indications for bands with lower censoring and conformance indexes in both the full account and subpopulation statistical service−life analysis.

Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category. Although not equivalent to dollar–years of service, SCE engineers estimate the mean time to wear–out of an overhead capacitor bank is about 30 years. Approximately 11,388 capacitor banks were installed in the overhead system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –206.4 percent realized from $138,400,064 of retirement activity constituting 8.8 percent of derived addition over the period 2002–2015. More recent 5–year rolling bands ending in 2013, 2014,and 2015 show negative net salvage rates exceeding –300 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –195 and –538 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and three percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −538 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 366.00 – UNDERGROUND CONDUIT

DESCRIPTION

This account includes the installed cost of underground conduit and tunnels used for housing distribution cables or wires. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	59-R3	59-R3
Future NS Rate	-30.0%	-401.0%
Realized NS	-183.1%	
Average Age (yrs.)	14.2	
Derived Additions	$1,848,035,134	
Plant Retirements	$36,174,527	
Percent Retired	2.0%	
Plant Balance	$1,811,860,607	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Conduit failures are generally the result of mechanical damage caused by excavating or drilling crews inadvertently digging into or drilling through the duct. The statistical service life analysis for this account is based on highly censored trials with indicated average service lives exceeding 70 years. Additionally, only minimal retirement activity of $36M from derived additions exceeding $1.8B has been reported. Constituting 2.0 percent of derived additions, this retirement activity is considered insufficient to provide a reliable basis for service life estimation.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Conduit	789,932,796	44	93-S3	93.0
Pull and Slab Boxes	447,741,061	25	50-S2	50.5
Vaults	324,651,530	18	79-S2	80.6
Excavation Trenches	16,836,983	1	184-R4	100.0
Non-unitized	75,629,378	4		
Other	157,068,859	9	49-L1	45.0
Total	1,811,860,607	100	76	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily risers, manholes, and blower assemblies.

As noted with the full account analysis, high censoring of the subpopulations also produces indeterminate service life indications.

LIFE ESTIMATION

With consideration given to the minimal retirement experience in this account and the resulting unreliable service–life indications, Foster Associates deferred to the Company in recommending retention of the currently approved 59–R3 projection service–life parameters.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –183.1 percent. As noted above, however, this history provides minimal retirement activity over the period 2002–2015.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –108 and –401 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −401 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 367.00 – UNDERGROUND CONDUCTORS AND DEVICES

DESCRIPTION

This account includes the installed cost of underground conductors and devices used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R0.5	43-R1.5
Future NS Rate	-60.0%	-261.0%
Realized NS	-155.7%	
Average Age (yrs.)	11.0	
Derived Additions	$5,946,990,287	
Plant Retirements	$398,585,960	
Percent Retired	7.2%	
Plant Balance	$5,548,404,327	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

The majority of SCE's underground cable population is XLPE, which generally fails due to breakdown of insulation over time. The statistical service life analysis for this account indicates average service lives in a narrow range between 40.5 and 44.7 years with lower modal dispersions for trials with lower censoring, conformance indexes, and hazard functions not compromised by negative or declining rates.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
Cable	4,452,641,073	80	45-R2	18.6
Non-unitized	288,856,647	5		
Other	809,879,908	15	27-L1	18.1
Total	5,551,377,628	100	42	

Table 2. Major Structural Components

Equipment classified in the "Other" category includes primarily circuit breakers and switches.

An analysis of the subpopulations indicates a 27–L1 and a 45–R2 service life curves with lower modal dispersions and a dollar–weighted mean of 42 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, non–homogeneous plant category.

LIFE ESTIMATION

Based on these observations and considerations, a 45–R1.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Although not equivalent to dollar–years of service, SCE engineers estimate a mean time to failure (MTTF) of 41 years for cross–linked polyethylene (XLPE) and 46 years for tree retardant cross–linked polyethylene (TR–XLPE) conductor. Company engineers also estimate that the mean time to wear–out of underground mainline and radial oil switches is about 35 years and the mean time to wear–out of an underground capacitor bank is about 30 years and 25 years for automatic reclosers. Approximately 11,549 subsurface oil–filled switches, 2,253 capacitor banks and 47 automatic reclosers were installed in the underground system at year–end 2015.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –155.7 percent realized from $398,585,960 of retirement activity constituting 6.7 percent of derived addition over the period 2002–2015. The most recent four 5–year rolling bands show negative net salvage rates exceeding –150 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –112 and –261 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −261 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 368.00 – LINE TRANSFORMERS

DESCRIPTION

This account includes the investment in overhead and underground distribution line transformers used in transforming electric energy to secondary voltages. Equipment continues to be classified in this account regardless of whether actually in service or held in reserve for future use. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	33-R1	33-S1.5
Future NS Rate	-20.0%	-47.0%
Realized NS	-46.9%	
Average Age (yrs.)	12.5	
Derived Additions	$4,034,390,510	
Plant Retirements	$525,751,213	
Percent Retired	15.0%	
Plant Balance	$3,508,639,297	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Distribution transformers are replaced when they fail in service or when deterioration is observed during inspection or other field work. Deterioration includes leaks, corrosion and damage caused by vehicles or acts of nature. The statistical service life analysis for this account is stable and indicates average service lives in the mid–20s to high–30s and lower modal dispersions for bands with lower censoring and conformance indexes. It should be noted, however, that "cradle–to–grave" accounting is used for line transformers and associated equipment (*e.g.*, capacitors and network protectors). Service lives indicated from a statistical analysis provide estimates of the age at which transformers are permanently retired from service.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

Category	Investment Amount ($)	Investment %	Full Band PLife-Curve
Undeground Transformers	1,262,937,734	36	34-S2
Overhead Transformers	1,045,618,106	30	40-S2
Fuseholders	749,306,101	21	38-S3
Non-unitized	57,769,013	2	
Other	393,008,343	11	25-O2
Total	3,508,639,297	100	36

Table 2. Major Structural Components

An analysis of the subpopulations indicates average service lives between 25 and 40 years with lower modal dispersions and a dollar–weighted mean of 36 years. Service–life indications derived from a statistical analysis of the combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Service–life indications from both the full account and subpopulation polynomial analyses bound the currently approved 33–S1.5 projection life–curve. Adjusting the currently approved parameters would imply a degree of precision beyond that which can be measured or estimated from a statistical life analysis.

Based on these considerations, retention of a 33–S1.5 projection–life is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –46.9 percent realized from $525.8M of retirement activity constituting 13.0 percent of derived addition over the period 2002–2015. Most recent 5–year rolling bands show negative net salvage rates exceeding –130 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –27 and –47 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions.

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −47 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 369.00 – SERVICES

DESCRIPTION

This account includes the installed cost of overhead and underground services used for distribution purposes. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	45-R1.5	45-R1.5
Future NS Rate	-100.0%	-387.0%
Realized NS	-271.0%	
Average Age (yrs.)	17.2	
Derived Additions	$1,347,309,968	
Plant Retirements	$45,902,562	
Percent Retired	3.5%	
Plant Balance	$1,301,407,406	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

Overhead (OH) services are typically installed in older urban areas and remote rural areas where it is cost prohibitive to install conductor underground. Services are installed underground (UG) in newer urban areas and in new rural areas under development. Forces of retirement acting upon UG services are comparable to those acting upon UG primary conductors such as operating temperature, insulation type, vintage of cables, installation method, manufacturing quality, corrosive environment and where installed.

The statistical service life analysis for this account is based on highly censored (63-79 percent) samples producing unreliable service–life indications for a majority of trials. The analysis reveals a few inconclusive indications with service lives between the low–40s and mid–60s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

	Investment		Full Band	Censoring
Category	Amount ($)	%	PLife-Curve	(%)
UG Service Conductor	783,834,596	60	71-S2	85.4
OH Service Conductor	387,892,896	30	52-R1.5	70.6
Risers	63,694,659	5	64-R2	77.8
Non-Unitized	21,112,757	2		
Other	44,872,497	3	79-R2	82.1
Total	1,301,407,406	100	65	

Equipment classified in the "Other" category includes primarily underground conduit.

An analysis of the subpopulations indicates full–band average service lives between 52 and 79 years with lower modal dispersions and a dollar–weighted mean of 65 years. Subpopulation service life indications are similarly based on highly censored trials and the resulting indications are considered less than conclusive.

LIFE ESTIMATION

Neither the full account nor the subpopulation analysis provides sufficient evidence to warrant adjusting the currently approved 45–R1.5 projection life and curve. It was also revealed in conducting the analysis of this account that the pricing and vintaging of retirements may be contributing to the observed high degrees of censoring. Pending further investigation of the ageing of retirements, Foster Associates concurs with SCE that current parameters should be retained for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands show negative net salvage rates exceeding –500 percent.

The per–unit net salvage analysis conducted for this account indicates future net salvage rates ranging between –178 and –387 percent, depending upon the rate of future inflation. Inflation rates ranging between zero and 2.72 percent were assumed in the analysis. Future net salvage rates would increase with longer projection lives and/or lower modal retirement dispersions..

NET SALVAGE ESTIMATION

Based on the above analysis, a future net salvage rate of −387 percent (derived from a 2.72 percent inflation rate) is recommended for consideration by SCE.

Distribution Plant
Account: 370.00 – Meters

Description

This account includes the cost of smart meters, devices and related appurtenances for use in measuring the electricity delivered to its users, whether actually in service or held in reserve. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	20-R3	20-R3
Future NS Rate	-5.0%	0.0%
Realized NS	-2.4%	
Average Age (yrs.)	7.7	
Derived Additions	$896,271,606	
Plant Retirements	$1,349,434	
Percent Retired	0.2%	
Plant Balance	$894,922,172	

Table 1. Account Parameters and Statistics

Life Analysis

SCE has a population of slightly over 5 million installed meters. With the exception of a small number (less than 20 thousand) of electromechanical meters, AMI meters have been deployed systemwide. A large–scale migration to AMI meters began in 2009 following a pilot program in 2007–2008. The relatively recent deployment of AMI meters produces an insufficient sample of retirements to draw inferences from a statistical analysis. Censoring is about 99 percent.

Life Estimation

AMI meters are electronic devices encased in plastic, typically installed in harsh environments, exposed to extreme weather conditions, and targets for vandalism. While the metrology element used in smart meters is generally considered mature and reliable technology, the life–span of the communication element is far from certain. Metering communication technology and protocols overlaid on electronic meters are rapidly evolving and will likely accelerate the rate of smart meter replacements relative to older–style, electromechanical metering equipment.

Lacking life analysis indications, the service life estimation for this account is based on a consideration of design life (20 years) and the opinions of Company engineers and operations personnel familiar with smart meters and ever evolving communications technology. Foster Associates therefore deferred to SCE in recommending retention of the currently approved 20–R3 projection life–curve for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account is based upon a minimal amount of $1.3M retired between 2011 and 2015 from derived additions exceeding $896M. The analysis indicates an overall net salvage rate of –271.0 percent realized from $45.4M of retirement activity constituting 3.4 percent of derived addition over the period 2002–2015. The most recent three 5–year rolling bands indicate negative net salvage rates exceeding –500 percent. The historical net salvage recorded in this account is not considered to be a reasonable predictor of future net salvage for AMI meters.

NET SALVAGE ESTIMATION

Noting that "cradle–to–grave" accounting is used for meters and associated equipment (*e.g.*, current and potential transformers), minimal salvage and cost of disposal are expected for this account. Meter removal and reinstallation costs are charged to expense. Based on these observations and expectations, a zero percent future net salvage rate is recommended for consideration by SCE.

DISTRIBUTION PLANT
ACCOUNT: 373.00 – STREET LIGHTING AND SIGNAL SYSTEMS

DESCRIPTION

This account includes the installed cost of equipment used wholly for public overhead street and highway lighting. Account statistics and current and proposed parameters are shown in Table 1 below.

	Current	Proposed
Plife-Curve	40-L0.5	48-L1
Future NS Rate	-30.0%	-100.0%
Realized NS	-111.3%	
Average Age (yrs.)	15.5	
Derived Additions	$974,350,403	
Plant Retirements	$102,266,782	
Percent Retired	11.7%	
Plant Balance	$872,083,621	

Table 1. Account Parameters and Statistics

LIFE ANALYSIS

During the last 15 years, SCE undertook an accelerated steel pole replacement program to address structural integrity deterioration and related public safety concerns. Pole deterioration found during this program was attributable to atmospheric and water corrosion, and pole, nut and anchor bolt rust. The majority of retired poles were replaced with concrete poles.

The Company conducts annual compliance patrolling and visual inspection of systems and facilities to identify safety issues early. The potential service life of concrete poles is enhanced by adding chlorine ion intrusion inhibitors and using high quality attachments with galvanized coatings.

The major forces of retirement for street light poles include car accidents, deterioration, idled facilities, and street upgrades and relocations.

The statistical service life analysis for this account is reasonably stable for trials with lower censoring, conformance indexes, and non–negative fitted hazard functions. Indications from such trials support average service lives between the lower 40s and mid–50s.

The composition of major categories (or subpopulations) of plant classified in this account at December 31, 2015 and the service life indications obtained from a full–band statistical analysis of each category are shown in Table 2 below.

An analysis of the subpopulations indicates full–band average service lives between 27 and 67 years with lower modal dispersions and a dollar–weighted mean of 54 years. Service–life indications derived from a statistical analysis of the

Category	Investment Amount ($)	%	Full Band PLife-Curve	Censoring (%)
Poles	388,111,928	46	58-S0.5	48.9
Cable & Conduit	260,964,203	31	67-R2	66.3
Light Fixtures	177,270,403	21	27-S0	2.4
Non-unitized	22,542,405	3		
Other	23,194,681	3	39-O2	38.3
Total	872,083,621	100	54	

Table 2. Major Structural Components

combined subpopulations are considered to be within a zone of reasonableness when compared to the subpopulation indications. The analysis of subpopulations does not indicate forces of retirement that would significantly bias the observed indications for a combined, nonhomogeneous plant category.

LIFE ESTIMATION

Based on these considerations and observations, a 48–L1 projection life–curve, derived from the full account broadest placement and observation bands, is considered reasonable and is recommended for this account.

NET SALVAGE ANALYSIS

The adjusted historical net salvage analysis for this account indicates an overall net salvage rate of –111.3 percent realized from $102,266,782 of retirement activity constituting 10.5 percent of derived addition over the period 2002–2015. The most recent 5 and 10–year rolling bands indicate net salvage rates exceeding –115 percent.

NET SALVAGE ESTIMATION

Based on these observations and the historical net salvage analysis, retention of the currently approved –100 percent future net salvage rate is recommended for consideration by SCE. It appears unlikely that lesser amounts of cost of removal will be realized in the future.

GENERAL PLANT DEPRECIABLE
ACCOUNT: 390.00 – STRUCTURES AND IMPROVEMENTS

DESCRIPTION

This account includes the cost in place of structures and improvements used for Company purposes, the cost of which is not properly includible in other structures and improvements accounts. Account statistics and current and proposed parameters are shown in Table 1 and the composition of major structural components classified in this account at December 31, 2015 is shown in Table 2.

	Current	Proposed
Plife-Curve	38-R3	45-R0.5
Future NS Rate	-5.0%	-10.0%
Realized NS	-24.5%	
Average Age (yrs.)	12.7	
Derived Additions	$1,035,908,700	
Plant Retirements	$88,821,443	
Percent Retired	9.4%	
Plant Balance	$947,087,257	

Table 1. Account Parameters and Statistics

Category	Investment Amount ($)	%
Common	229,531,472	24
Buildings	220,785,582	23
Power & Lighting Systems	170,306,642	18
HVAC	100,134,622	11
Alarms and Monitoring Systems	65,852,228	7
Foundations & Related Structures	57,908,077	6
Water Supply Systems	33,133,484	3
Non-unitized	27,376,214	3
Miscellaneous	42,058,937	4
	947,087,257	100

Table 2. Structural Components Distribution

LIFE ANALYSIS

The statistical service life analysis for this account indicates average service lives between 40 and 60 years for trials with lower censoring and conformance indexes. A number of trials are considered less reliable if hazard rates are unrealistically declining or zeroed to avoid the suggestion of negative hazard rates. No attempt was made to analyze equipment classified in the subpopulations for this plant category.

Life Estimation

Based on the indications obtained from the broader bands of the statistical life analysis, a 45–R0.5 projection life–curve is recommended for this account. Foster Associates was informed that Company engineers do not anticipate that future forces of retirement will be significantly different from those observed in the past for this plant category.

Net Salvage Analysis

The historical net salvage analysis for this account indicates an overall adjusted net salvage rate of –24.1 percent realized from $88.8M of retirement activity constituting 8.6 percent of derived addition over the 2002–2015 study period.

Net Salvage Estimation

Based on these observations and the expectation of continuing negative net salvage, a –10 percent future net salvage rate is recommended for consideration by SCE. This recommendation adjusts the future net salvage parameter from a –5 percent in the direction of the historical net salvage observations.

Appendix B

Formulation of Per Unit Net Salvage Rates

Formulation of Per-unit Net Salvage Rates

Average realized net salvage per unit retired for the kth subpopulation of a plant account is given by

$$\overline{NSR_k} = \frac{\sum_{2009}^{2015} NSR_{jk}}{\sum_{2009}^{2015} NUR_{jk}}$$

where

NSR_j = net salvage realized in the j^{th} activity year; and
NUR_j = number of units retired in the j^{th} activity year.

The installed cost per unit of plant remaining in service at December 31, 2015 from the i^{th} vintage of the kth subpopulation of a plant account is given by

$$ICU_{ik} = \frac{PIS_{ik}}{NUS_{ik}}$$

where

PIS_{ik} = plant in service from the i^{th} vintage of the k^{th} subpopulation; and
NUS_{ik} = number of units in service from the i^{th} vintage of the k^{th} subpopulation.

The ratio of the net salvage per unit retired to the installed cost of the i^{th} vintage of the kth subpopulation of a plant account becomes

$$PUR_{ik} = \frac{\overline{NSR_k}}{ICU_{ik}}.$$

The plant–weighted average of vintage subpopulation ratios used to estimate the future net salvage of vintages at the account level (*i.e.*, the sum of subpopulation vintages) is given by

$$\overline{PUR_i} = \frac{\sum_{k=1}^{n} (PIS_{ik})(PUR_{ik})}{\sum_{k=1}^{n} PIS_{ik}}$$

where

n = number of subpopulations within a plant account.

Forecasted retirements from the i^{th} vintage in the jth activity year are the product of plant in service at December 31, 2015 and the probability of retirement in activity years beyond 2015 obtained from an Iowa–type probability density function. Retirements from the i^{th} vintage in the j^{th} activity year are given by

$$RET_{ij} = \left(PIS_i\right)\left(p_{ij}\right)$$

where

p_{ij} = probability of retirement during age interval $j–i–0.5$ and $j–i+0.5$.

Estimated future net salvage for retirements from the i^{th} vintage in the j^{th} activity year is given by

$$FNS_{ij} = RET_{ij}\left(\overline{PUR_i}\right)\left(1+r\right)^{j-2015}$$

r = estimated rate of inflation.

where

The estimated future net salvage rate for a plant account is the ratio of the sum of future net salvage to the sum of vintaged plant in service given by

$$FNS = \frac{\sum_i \sum_j FNS_{ij}}{\sum_i \sum_k PIS_{ik}}.$$

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
JACOB W. MOON

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-9)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)** **)** **)**	**Dkt. No. ER18-______-000**

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JACOB W. MOON

(EXHIBIT SCE-9)

Mr. Moon sponsors three main portions of Southern California Edison Company's ("SCE") proposed Formula Rate and associated Formula Rate Protocols: 1) separation of existing transmission and distribution facilities under the Operational Control of the California Independent System Operator Corporation ("CAISO" or "ISO") from SCE's non-ISO controlled facilities (see following Sections II and III); 2) forecast ISO direct capital expenditures that will translate into forecast plant additions and forecast Construction Work-In-Progress ("CWIP") used in the proposed Formula Rate (*see* Sections IV, V, and VI); and 3) determination of the portion of operation and maintenance ("O&M") expense booked as transmission that is associated with ISO transmission facilities (*see* Section VII). In Sections II and III, Mr. Moon discusses: 1) the methodology used in the proposed Formula Rate to identify and separate SCE's transmission and distribution ("T&D") facilities under the operational control of the CAISO from SCE's non-ISO facilities as reflected in Schedule 7 (*see* Section II); and 2) the determination of High Voltage and Low Voltage gross plant percentages as reflected in Schedule 31 (*see* Section III). In Section IV, he also sponsors forecast direct capital expenditures that will contribute to plant additions to rate base and the Federal Energy Regulatory Commission-approved CWIP in rate base through December 2018 as reflected in Schedules 10 and 16. In Section V, Mr. Moon provides the general overview, current status, expected activities, and associated major cost components for these plant additions and CWIP in rate base. He also describes SCE's CWIP tracking procedure and exclusions. In Section VI, Mr. Moon also briefly describes Statement BM – Construction Program Statement showing that the projects for which CWIP in rate base treatment is sought are part of a prudent, least-cost energy supply program that includes consideration of alternatives. Lastly, in Section VII, Mr. Moon explains how SCE's proposed Formula Rate determines the O&M expenses for T&D accounts as reflected in Schedule 19. He also discusses how the proposed Formula Rate assigns T&D O&M expenses to ISO and non-ISO functions as reflected in Schedules 19 and 27.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER18-______-000**

PREPARED DIRECT TESTIMONY OF
JACOB W. MOON
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Jacob W. Moon, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Senior Finance Project Manager in the Operational Finance department within the Finance organizational unit. My primary responsibilities include managing the preparation of financial materials from the Transmission and Distribution ("T&D") organizational unit associated with SCE's filings before the Federal Energy Regulatory Commission ("FERC" or "Commission") and the California Public Utilities Commission ("CPUC").

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science degree in Mathematics and Applied Science with an emphasis in Actuarial Science from the University of California, Los Angeles and a Master of Business Administration degree from the A. Gary Anderson Graduate School of Management at the University of California, Riverside.

I joined SCE in 2000 as a Professional Aide. I was promoted to Financial Analyst in 2002 and Senior Financial Analyst in 2005. In 2007, I transferred to Edison International (parent holding company of SCE). In 2011, I returned to SCE as a Senior Finance Project Manager and assumed my current position.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I sponsored testimony supporting the request for recovery of SCE's abandoned plant costs in Docket Nos. ER12-239, ER14-1857, and ER16-1025.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the methodology used in the proposed Formula Rate to identify and separate SCE's T&D facilities under the Operational Control of the ISO from SCE's non-ISO facilities as reflected in Schedule 7 of Exhibit No. SCE-4 (Section II), and to describe the methodology used to split SCE's ISO T&D facilities into High Voltage ("HV") and Low Voltage ("LV") categories, as reflected in Schedule 31 of Exhibit No. SCE-4 (Section III). In addition, I provide SCE's transmission capital expenditures forecast for the period January 1, 2017 through December 31, 2018 (Section IV). This forecast is an input used in determining the Incremental Forecast Period Transmission Revenue Requirement ("TRR"). Also, I describe SCE's CWIP expenditure tracking procedure and exclusions (Section V) and Statement BM (Section VI). Finally, in Section VII, I explain how SCE's proposed Formula Rate determines the O&M expense component of the Prior Year TRR. I also explain how the proposed Formula Rate assigns recorded O&M expenses to SCE facilities under the Operational Control of the CAISO.

The methodology is briefly described in Section 10 of SCE's Protocols for the proposed Formula Rate, and it is discussed more fully by Mr. Allstun (Exhibit No. SCE-10).

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 7 (Plant Study), the majority of Schedule 19 (O&M) (except for the allocators sponsored by Mr. Allstun on Lines 48-85, Column 5), the portion of Schedule 27 (Allocators) relating to the calculation of the O&M allocators (Lines 24-48), and Schedule 31 (HV/LV).

II. SEPARATION OF EXISTING T&D FACILITIES INTO ISO AND NON-ISO FACILITIES

Q. How does SCE separate its T&D facilities plant into ISO and non-ISO for ratemaking?

A. Pursuant to Section 9 of the proposed Formula Rate Protocols, SCE performs a "Plant Study" which separates SCE's investment in T&D plant into ISO and non-ISO.

Q. What is the Plant Study?

A. The Plant Study is a study that SCE performs in order to separate its T&D plant into ISO and non-ISO categories. The Plant Study analyzes SCE's existing facilities and determines which facilities are under the ISO's Operational Control. In the proposed Formula Rate, plant classified as Transmission under the Commission's Uniform System of Accounts that is under the ISO's Operational Control is called "Transmission Plant – ISO", while Distribution Plant under the ISO's Operational Control is called "Distribution Plant – ISO". As discussed below in Section III, the Plant Study further subdivides Transmission Plant – ISO and Distribution Plant – ISO into HV and LV categories. As of the time of this testimony, SCE has no distribution facilities under the Operational Control of the ISO, but Distribution Plant – ISO is still kept in the proposed Formula Rate as a placeholder.

Q. Is the use of the Plant Study in setting SCE's transmission rates a new concept?

A. No. SCE has been performing the Plant Study since the establishment of the ISO in 1998. Further, the results of the Plant Study have been used in SCE's FERC rate cases since the establishment of the ISO. The Plant Study used in conjunction with this filing was performed in the first quarter of 2017.

Q. Why does SCE perform this study?

A. SCE performs the Plant study because its accounting records do not directly identify the portion of SCE's T&D plant that is under the Operational Control of the ISO and this separation is needed for both FERC and CPUC ratemaking purposes. Generally, SCE records investment in T&D facilities to the corresponding FERC plant account with locational identifiers. For substation facilities, the locational identifier typically refers to a specific substation location. For transmission lines, the locational identifier may refer to a specific line, group of lines, or voltage. Some of these facilities are easily classified as network facilities that are 100% ISO, or radial facilities that are 100% non-ISO. Other facilities, like shared-use locations for transmission lines and substations with both ISO and non-ISO facilities, and dual use facilities that support ISO and non-ISO functions, such as substation fencing, buildings, and grounding grid, need to be classified as ISO and non-ISO on an allocation basis. As such, Section 9 of SCE's proposed Protocols provides for SCE to perform an annual Plant Study in order to separate ISO from non-ISO plant, using the methodology set forth below.

Q. How is SCE's Plant Study reflected in the Formula Rate?

A. The results of the Plant Study are summarized on an account-by-account basis in Schedule 7 of the proposed Formula Rate (Exhibit No. SCE-4). These values form the basis for plant in service as identified in Schedule 6 described in Mr. Gunn's testimony, Exhibit No. SCE-7, and the derivation of HV and LV Gross Plant Percentages identified in Schedule 31 of Exhibit No. SCE-4, described in Section III below.

Q. Please describe the methodology used in the proposed Protocols for separating T&D plant into ISO and non-ISO.

A. The proposed Protocols first address the separation of T&D plant recorded to Accounts 350-359, and 360-362 (Section 9(b) of the proposed Protocols). Each asset location within these accounts is placed into one of the following five categories:

1. All ISO: Facilities for which all assets at the location are under the Operational Control of the ISO.
2. Non-ISO: Facilities for which all assets at the location are not under the Operational Control of the ISO.
3. Mixed ISO and Non-ISO Substation: Substation facilities that have a mixture of plant under ISO Operational Control and not under ISO Operational Control. These assets are individually examined to determine which are under the ISO control and which are not. Assets under ISO Operational Control are classified as ISO, while assets not under ISO Operational Control are classified as non-ISO. Assets performing a dual use function (both ISO and non-ISO) are allocated based on the percentages of ISO/non-ISO assets at the asset location.

4. Mixed ISO and Non-ISO Lines: Transmission lines that have a mixture of plant under ISO Operational Control and not under the Operational Control of the ISO. These assets are allocated using the transmission line classification method, discussed below.
5. Other: Substation facilities that do not fall into one of the above first three categories in a location are classified as ISO or Non-ISO in proportion to the total percentage of Transmission Plant – ISO or Distribution Plant – ISO determined in above categories (1) through (3).

Q. Please describe the transmission line classification method referred to above.

A. Transmission line classification is addressed in Section 9(c) of the proposed Protocols. Transmission lines that have a mixture of assets under the ISO's Operational Control and not under the ISO's Operational Control are allocated on a line-mile basis. For example, if in a particular location 8 miles of a 10-mile transmission line are under ISO Operational Control and 2 miles are not, 80 percent of the cost of the line will be classified as ISO and 20 percent as non-ISO. Using line miles is a reasonable method for dividing the costs of these mixed-use assets as it allocates costs in proportion to ISO and non-ISO facilities for the asset under consideration.

Q. Will SCE make the Plant Study available to its customers for their review in each Annual Update process?

A. Yes. The proposed Protocols provide for SCE to provide a summary of Plant Study for the Prior Year in its annual Draft Annual Update posting. This summary appears as Schedule 7 in the Formula Rate (Exhibit No. SCE-4). In addition, the proposed Protocols provide that a copy of the complete Plant Study for the Prior Year will be included in the workpapers. In this filing, SCE is including a copy of the Plant Study for the Prior Year of 2016 in its workpapers, Exhibit No. SCE-22.

Q. How much recorded T&D plant does SCE attribute to ISO?

A. As shown on Schedule 7, of Exhibit No. SCE-4, SCE attributes $8,276,570,295 of transmission plant (Line 21, Column 2) and $0 of distribution plant (Line 30, Column 2) to ISO for the Prior Year.

III. CALCULATION OF HV AND LV PERCENTAGES

Q. How does SCE calculate HV / LV split of ISO plant?

A. SCE divides ISO Transmission plant into HV and LV categories based on the methodology set forth in Section 12 of Rate Schedule 3 to Appendix F of the ISO Tariff, and thereby calculates the HV and LV percentages that are included in Schedule 31 of the proposed Formula Rate, Exhibit No. SCE-4.

Q. Please describe Schedule 31.

A. Schedule 31 of Exhibit No. SCE-4 contains information and calculations used in determining the HV and LV percentages of total ISO Gross Plant. SCE, in accordance with the ISO Tariff, defines a HV Facility as having an operating voltage of 200 kV or higher, while an LV Facility is one having an operating voltage of less than 200 kV. The ISO Tariff also provides direction in Appendix F, Schedule 3, Section 12 on how a Participating Transmission Owner ("PTO") such as SCE should determine HV and LV Gross Plant percentages. Schedule 31 of Exhibit No. SCE-4 implements the direction provided in the ISO Tariff.

In Schedule 31, all Transmission Plant – ISO and Distribution Plant – ISO from the Plant Study is classified into one of five categories: 1) HV Transmission Lines; 2) LV Transmission Lines; 3) HV Substations; 4) Straddle Substations; and 5) LV Substations. Gross Plant for categories 1 and 3 is classified as all HV, while Gross Plant for categories 2 and 5 is classified as all LV. Straddle Substations have operating voltages both above and below 200 kV, and as such contain both HV and LV Gross Plant. Gross Plant for "Straddle Substations" is specifically examined to determine the operating voltage of components within the facility. The Gross Plant within the Straddle Substations that operates as HV is identified as HV Gross Plant, while the Gross Plant that operates as LV is identified as LV Gross Plant. The only plant that operates at both HV and LV are "HV/LV Transformers." The Gross Plant associated with these HV/LV Transformers is attributed to HV and LV in proportion to the HV/LV percentages of all other ISO Gross Plant. SCE also classifies forecast capital additions and incentive project CWIP as either HV or LV based on the HV/LV percentages of ISO Gross Plant.

Q. What percentage of SCE ISO plant is considered High Voltage?

A. As shown on Schedule 31 of Exhibit No. SCE-4, Line 37, 97.596% of recorded and forecast plant is identified as HV and 2.404% as LV.

IV. CAPITAL EXPENDITURE FORECAST

Q. What capital expenditures are included in the proposed Formula Rate?

A. The proposed Formula Rate includes SCE's ISO capital expenditure forecast for the period January 1, 2017 through December 31, 2018. These expenditures translate into forecast plant additions and/or forecast CWIP used in proposed Formula Rate Schedules 10 for Forecast Period Incremental CWIP by Project and Schedule 16 for Forecast Plant Additions for In-Service ISO Transmission Plant located in Exhibit No. SCE-4.

Q. Please describe what you mean by "capital expenditures".

A. Capital expenditures as used in my testimony represent direct T&D capital expenditures such as labor, materials, contract, other, and allocated T&D

organizational unit division overhead costs. Capital expenditures as used in this context do not include capitalized corporate overheads added in the plant additions process as described by Mr. Gunn in Exhibit No. SCE-7.

Q. What are the components of the forecast direct capital expenditures that you are sponsoring?

A. I am sponsoring two categories of direct capital expenditures – the expenditures associated with incentive and non-incentive ISO transmission facilities that are projected to be either added to rate base or placed in service during the period January 2017 through December 2018.

Q. Please provide a description of the non-incentive ISO transmission facilities that are included in your capital forecast.

A. The non-incentive ISO transmission facilities represent those facilities that will be under the Operational Control of the CAISO, but have not been afforded any project-specific incentives by the Commission. The non-incentive ISO transmission facilities are further broken down as Blanket Specifics or Specific Project work orders.

Blanket Specifics work orders represent capital expenditures for routine work with no specific planned in-service date that can be grouped together from an operational and accounting perspective. Examples include transformer and pole replacements. Without a specific planned in-service date, capital expenditures forecast in January will close to plant in the same time period. Specific Project work orders represent unique capital expenditure activities that are carried out as individual projects with a planned in-service date. The in-service date shown in the workpapers is used to estimate the month and year when the total accumulated construction costs will close to plant or rate base. Exhibit SCE-22 (WP Schedule 16 – Summary of ISO Cap Expenditures Non-

Inc Projects, “Total Non-Incentive Transmission Projects” line) displays the Blanket Specifics and the Specific non-incentive project work orders that I am sponsoring. In total, those non-incentive work orders represent $748 million in ISO transmission projects forecast to be placed in service during the period January 2017 through December 2018.

Q. Please provide a description of the incentive ISO transmission facilities that are included in your capital forecast

A. Incentive projects include facilities that will be under ISO Operational Control for which SCE has received Commission approval of a project-specific incentive such as 100% of CWIP in rate base prior to being placed in service, or incentive return on equity (“ROE”) adders. SCE has received approval to include 100% of CWIP in rate base for seven projects that affect the forecast: 1) Devers-Colorado River (“DCR”) Project; 2) Tehachapi Renewable Transmission Project (“TRTP” or “Tehachapi); 3) Red Bluff Substation Project (“Red Bluff”); 4) Colorado River Substation Expansion (“CRS Expansion”); 5) Whirlwind Substation Expansion (“Whirlwind Expansion”); 6) Calcite Substation (formerly Jasper, part of South of Kramer Transmission Project) (“Calcite”); and 7) West of Devers Transmission Project (“West of Devers”). In total, these seven incentive projects represent approximately $312 million in CWIP expenditures forecast to be under construction during the period January 2017 through December 2018, Exhibit No. SCE-22, (Workpaper to Schedule 10 Forecast CWIP Capital Expenditures by PIN and Activity). A portion of the facilities associated with these incentive projects will be placed in-service during this period as discussed later in my testimony. Once placed in service, the CWIP expenditures will be excluded from CWIP in rate base. SCE’s CWIP capital expenditures forecast is summarized in workpapers, Exhibit No. SCE-22.

Q. Please generally describe the Capital Expenditure Forecasting process.

A. All estimated capital additions are derived from the construction costs already spent and included in CWIP at prior year-end and forecast capital expenditures for the Incremental Forecast Period. The forecast capital expenditures are included in SCE's annual corporate-wide capital expenditure forecast process that occurs in the second half of the year and culminates in an approved five-year capital budget and forecast, typically in the first quarter of the following year. This approved capital budget and forecast is what is referred to as the SCE's "5-Year Capital Budget and Forecast ("Capital Plan")." The Capital Plan includes a forecast of all transmission and distribution facilities (both ISO-related and non-ISO). Through this process, SCE reviews the expected capital expenditures and schedules for projects included in the forecast. In preparation for this proposed Formula Rate filing, SCE may update some of the assumptions in the Capital Plan to reflect known changes.

Q. Please summarize the capital forecast included in your testimony.

A. As discussed in my testimony, (and as noted in Exhibit No. SCE-22's WP Schedule 10&16 - Identification of ISO Projects above $5M) during the period January 2017 through December 2018, SCE forecasts:

- $748 million in ISO non-incentive network transmission closings (including $395 million in ISO Blanket Specifics closings),
- $312 million in FERC incentive rate qualified CWIP expenditures, and;
- $68 million of CWIP Expenditures closing to plant (including $37 million of TRTP plant closings that have a ROE adder of 125 basis points (as noted in Schedule 14, Line 187 of Exhibit No. SCE-4)).

Q. How are the expenditures forecasts you are sponsoring utilized in the Formula Rate?

A. As explained in Exhibit SCE-7, Mr. Gunn utilizes the forecast expenditures to develop final amounts of additions to Forecast Net Plant Additions and Incremental CWIP to be included in the Forecast Period.

Q. Please provide a summary of the major transmission projects that SCE forecasts will be placed in service during the period January 2017 through December 2018.

A. As shown in my workpapers (WP Schedule 10 & 16 Identification of ISO Projects above $5M) included in Exhibit No. SCE-22, in addition to the numerous but relatively small transmission projects, there are 26 significant transmission projects (each $5 million or greater in ISO-related costs) that are expected to be placed in service in the period January 2017 through December 2018 – 10 Blanket Specifics, 14 Specific non-incentive projects, and 2 Specific incentive projects. These projects will increase the reliability of the ISO transmission grid, increase access to new generation resources to serve the ISO market, and/or provide congestion relief. The costs associated with these facilities are included in the Formula Rate proposed by SCE in this filing. SCE's proposed Formula Protocols, Section 3(a) specifies that SCE will provide workpapers detailing specific information regarding its capital forecast.

V. CWIP PROJECT EXPENDITURE TRACKING PROCEDURE AND EXCLUSIONS

Q. What are the forecast direct capital expenditures, by project, for the Incentive Projects that have received Commission approval for including 100% of CWIP in rate base?

A. Table 1 below provides a summary of forecast FERC-jurisdictional direct capital expenditures for Projects that have received Commission approval for, including CWIP in rate base. A monthly and detailed forecast of direct capital expenditures for these Projects is provided in the workpapers, Exhibit SCE-22.

Table 1
Forecast FERC CWIP Direct Capital Expenditures
(Nominal $Millions)

Project	2017	2018
Calcite Substation (formerly Jasper, part of South of Kramer)	$0.550	$2.900
West of Devers	37.761	239.814
Devers-Colorado River	(0.080)	0
Tehachapi	24.579	0
Red Bluff	0.005	0
Colorado River Substation Expansion	0.022	0
Whirlwind Substation Expansion	6.129	0
Total	**$68.967**	**$242.714**

Q. Please describe the process by which SCE tracks expenditures associated with the Projects.

A. Project expenditures are tracked at a summary level through unique Project designation in the SAP work management system. A Work Breakdown Structure ("WBS") is used to organize project information for work management and reporting purposes. Within each Project, unique work order numbers are established to track specific project elements. Work orders are designed to track costs over the full spectrum of activities necessary to develop and complete a project. The costs recorded to the Projects and work orders are monitored by Project Controls Engineers who use contracts, purchase orders and/or work authorizations to make sure the charges are valid for a particular work order.

Q. How does SCE ensure that the costs recorded and forecast for the Projects reflect only those facilities that, when completed, will be under the operational control of the CAISO?

A. All project costs are identified in the work orders by the jurisdiction through which they are recoverable (*i.e.*, FERC or CPUC). SCE creates unique FERC subaccount numbers for FERC-jurisdictional assets that are under the operational control of the CAISO. In addition, SCE creates different CPUC subaccount numbers for CPUC-jurisdictional assets.

Q. How does SCE ensure that costs for other transmission projects are not reflected in the CWIP associated with the Projects?

A. SCE uses specific work orders associated with the Projects identified in this filing to record and forecast CWIP expenditures.

Q. Have you excluded any Project costs from the CWIP forecast?

A. Yes. SCE has excluded telecommunications costs associated with the Projects, which are recorded in separate work orders. SCE has also excluded any CPUC-jurisdictional transmission and distribution costs associated with the Projects and costs not related to new construction (*i.e.*, removal and relocation costs for the new facilities).

Q. Please describe the detailed historic information that you included in this filing.

A. Detailed information on the nature of the construction expenditures SCE incurred for the period beginning January 1, 2016 through December 31, 2016 is provided in the workpapers to Schedule 10 – Recorded CWIP Expenditures 2016. The information is provided in a similar level of detail that SCE submitted in Docket Nos. ER10-160, ER11-1952, and ER11-3697.

VI. STATEMENT BM

Q. Please describe briefly Statement BM.

A. Statement BM of the Commission's regulations requires utilities seeking recovery of CWIP in rate base to provide a statement showing that the projects for which CWIP treatment is sought are part of a prudent, least-cost energy supply program that includes consideration of alternatives. Statement BM discusses SCE's transmission infrastructure expansion and describes how each of the Projects have undergone a rigorous and independent evaluation process before being approved by the CAISO and the CPUC. Such evaluations considered, among other things, the need for the Projects, the cost-effectiveness, and project alternatives. SCE is including a Statement BM with this filing.

VII. THE O&M EXPENSE FORMULA

Q. Please explain how the Formula Rate calculates total T&D O&M expense.

A. Total T&D O&M expense is calculated in Schedule 19, Part 1 of the proposed Formula Rate, Exhibit No. SCE-4. The starting point for calculating T&D O&M expense is SCE's annual recorded information reported in FERC Form 1 as shown in Schedule 19, Part 1, Column 2. In SCE's books and records, Transmission O&M expense is presented in Accounts 560-573 and Distribution O&M expense is presented in Accounts 580-598. Currently, only Transmission O&M expense is reflected in the proposed Formula Rate, and there is zero Distribution O&M expense.

Schedule 19 then separates the total FERC Form 1 O&M expense into certain sub-accounts as appropriate, then into labor and non-labor components using internal financial reports. The resultant labor amount net of NOIC ("Non-

Officer Incentive Compensation") is consistent with the true labor reported in FERC Form 1 Page 354 (Distribution of Salaries and Wages).

Next, the formula makes adjustments to the recorded O&M (Schedule 19, Part 1, Columns 7 and 8) to remove expenses that are recovered through other FERC-authorized rate mechanisms. These adjustments include the Reliability Services Balancing Account ("RSBA"), Transmission Access Charge Balancing Account ("TACBA"), and the Transmission Revenue Balancing Account ("TRBA") shown on Line 15. These adjustments also include the expenses that are recovered through CPUC authorized rate mechanisms, including the Energy Resource Recovery Account ("ERRA") shown on Lines 4 and 12 ("Scheduling, System Control and Dispatch Services" and "Wheeling Costs") and the Mojave Balancing Account ("MBA") shown on Line 7 ("MOGS Station Expense"), and any shareholder expenses shown on Lines 14, 26, and 39 ("Miscellaneous Transmission Expenses – Allocated," "Maintenance of Overhead Lines – Allocated," and "Accounts with no ISO Distribution Costs," respectively), if applicable.

Lastly, the formula adds in the Transmission NOIC and Distribution NOIC on Lines 32 and 40, respectively, which is paid out to T&D employees as further discussed in the testimony of Mr. Mindess (Exhibit No. SCE-12). These NOIC costs are appropriately included as part of functionalized O&M expense in Schedule 19 of Exhibit No. SCE-4.

The above adjustments result in "Adjusted Recorded O&M Expenses" which are shown in Schedule 19, Part 1, Line 43, Columns 9-11 of Exhibit No. SCE-4.

Q. Part 1 of Schedule 19 contains multiple lines for many accounts. Why is Schedule 19 presented in this manner?

A. This is necessary in order to calculate the adjustments discussed above and in order to determine how much of the recorded T&D O&M expenses are ISO-related. To accomplish this, the Formula Rate separates the FERC Form 1 O&M accounts into various components that further define the activities associated with the expenses recorded in each particular FERC Account. For example, the expenses recorded in Account 560, Operation Supervision and Engineering, are reported on Form 1 as one line item. However, some of the expenses recorded to this account relate to payments made to the Los Angeles Department of Water and Power ("LADWP") for Sylmar and Salt Water Project ("SRP") for Palo Verde O&M expenses related to shared ownership of ISO-controlled transmission facilities. These expenses are purely ISO-related, while other expenses in this account are not. The Formula Rate identifies payments to LADWP and SRP separately for purposes of allocating costs between ISO and non-ISO O&M expense (which is performed in Schedule 19, Part 2) as noted in Exhibit No. SCE-4.

Q. How does the Formula Rate determine the portion of the total Transmission and Distribution O&M expense (calculated in Schedule 19, Part 1) that is attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense")?

A. The portion of Total T&D O&M expense that is attributable to facilities under the Operational Control of the ISO is calculated in Schedule 19, Part 2 of Exhibit No. SCE-4. ISO O&M Expense is composed of expenses that are: 1) directly assignable to ISO and non-ISO facilities and activities; or 2) developed based on appropriate metrics that can be used to allocate the expenses between

ISO and non-ISO facilities and activities. For further discussion and reasonableness of SCE's proposed O&M allocation, please see Mr. Allstun's testimony (Exhibit No. SCE-10).

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Jacob W. Moon, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Jacob W. Moon

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Jacob Woong Moon, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
DANIEL J. ALLSTUN

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-10)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DANIEL J. ALLSTUN

(EXHIBIT SCE-10)

Mr. Allstun describes the proposed allocation methodology for Operation and Maintenance ("O&M") expenses reflected in SCE's proposed Formula Rate. Mr. Allstun explains the six allocators that SCE uses to assign O&M expenses to ISO Transmission on Schedule 19 within the proposed Formula Rate and provides justification for the reasonableness of SCE's proposal. Mr. Allstun also describes the calculation of the allocators reflected on Schedule 27 of the proposed Formula Rate.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Southern California Edison Company	**)))**	**Dkt. No. ER18-______-000**

**PREPARED DIRECT TESTIMONY OF
DANIEL J. ALLSTUN
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY**

Q. Please state your name and business address for the record.

A. My name is Daniel J. Allstun, and my business address is 8631 Rush St., Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Manager of FERC Contract and Cost Analysis in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include providing analysis and policy guidance supporting the development of pricing and related rate terms associated with contracts and services subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission"), as well as management of the implementation of SCE's formula transmission rate.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science Degree in Mechanical Engineering from California State University at Fullerton in May 1984. I joined SCE as an Engineer Trainee in the Nuclear Engineering, Safety and Licensing

Department in January 1983. In July 1984, I was promoted to the position of Licensing Engineer, working on licensing issues involving San Onofre Nuclear Generating Station, Unit 1. In January 1989, I transferred to the Regulatory Policy and Affairs Department as a Regulatory Cost Analyst. During my tenure with the Regulatory Policy and Affairs Department, my responsibilities have involved a host of regulatory issues including the restructuring of the natural gas industry, the restructuring of the electric industry, and cost and policy analysis of various gas and electric issues. From 1994 through 2005, my primary responsibility was analysis of SCE's FERC-jurisdictional contracts and policies. Since 2006, my primary responsibility has focused on directing cost of service analysis, rate recovery, and involvement in various rate-related proceedings at FERC.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I sponsored testimony in Docket Nos. ER17-250, ER16-1025, ER14-1857, ER12-239, ER11-1952, ER10-160, ER09-1534, ER09-187, ER08-1343, ER08-375, ER06-186, EL04-137, ER03-549, ER02-2189, ER02-925, and ER98-441.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the six allocators that SCE uses for the allocation of transmission and distribution ("T&D") Operation and Maintenance ("O&M") expenses to SCE's cost of service for its T&D assets under the Operational Control of the California Independent System Operator ("ISO") on Schedule 19 within the proposed FERC Formula Rate (Exhibit No. SCE-4). These allocated O&M expenses are included in SCE's Transmission

Revenue Requirement ("TRR"). I also provide justification for the reasonableness of SCE's O&M allocation proposal and briefly describe the calculation of the allocators reflected on Schedule 27 of the proposed Formula Rate.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the allocation factors used in Schedule 19 (O&M) which appear on Schedule 19 on Lines 48-87, Column 5.

II. OVERVIEW OF SCE'S PROPOSED O&M ALLOCATION

Q. Please explain how the proposed Formula Rate calculates total T&D O&M expense.

A. As discussed more fully by Mr. Moon (Exhibit No. SCE-9), the total adjusted T&D O&M expense is calculated in Schedule 19, part 1, of the proposed Formula Rate. Schedule 19, part 1, also separates the total FERC Form 1 T&D O&M expense into certain sub-accounts, as appropriate, and into labor and non-labor components using internal financial reports. Finally, the adjusted T&D O&M is attributed to ISO using various allocation factors performed in Schedule 19, part 2, of the proposed Formula Rate.

Q. What is the methodology used by the proposed Formula Rate to allocate the portion of the total T&D O&M expense attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense") included in SCE's TRR?

A. The proposed Formula Rate O&M allocation methodology consists of two parts: 1) directly assignable expenses; or 2) allocated expenses based on metrics that are used to allocate the expenses between ISO and non-ISO.

This is similar to the methodology currently in place under SCE's Original Formula Rate.

Q. How does the O&M allocation methodology proposed in the proposed Formula Rate differ from the Original Formula Rate?

A. As discussed more below, SCE is seeking to improve the O&M allocation in its proposed Formula Rate. Specifically, the new allocation methodology maintains principles of cost allocation based on causation, however it is designed to be even more transparent, readily subject to external verification by the Commission and stakeholders, and easier to replicate by third parties when compared to the Original Formula Rate.

III. REASONABLENESS OF ALLOCATION METHODOLOGY

Q. Do you believe the proposed Formula Rate allocation methodology for the O&M expense between ISO and non-ISO is reasonable?

A. Yes. As I noted above, SCE is proposing to refine the O&M allocation methodology in its proposed Formula Rate. As such, SCE is seeking to reduce the number of allocation factors from 23 to 6. The six proposed allocators are 100% ISO, 100% non-ISO, and four asset-driven allocators. In contrast, the Original Formula Rate used 23 different allocators (100% ISO, 100% non-ISO, 17 operational allocators and 4 secondary labor allocators). In addition, SCE has reduced the number of FERC sub-accounts in the proposed Formula Rate to 30 (plus a Non-Officer Incentive Compensation ("NOIC") subaccount) for Transmission and 5 for Distribution (plus a NOIC subaccount). The Original Formula Rate used 49 sub-accounts (plus a NOIC) for Transmission and 9 sub-accounts (plus NOIC) for Distribution.

Below, I will first explain the methodology that SCE uses to determine how costs will be allocated to transmission rates. This allocation methodology, generally speaking, relies on direct cost assignment, line miles, and circuit breaker counts. I will then explain which category of costs is covered by each of the allocation principles noted above. I would like to first explain the asset allocators that SCE will use in more detail.

Q. What allocators is SCE proposing to use?

A. SCE is proposing to use direct assignment (100% ISO or 100% non-ISO), line miles (overhead and underground), and circuit breaker counts for purposes of O&M cost allocation.

Q. Can you please explain direct assignment?

A. Direct assignment is the most accurate way to allocate costs. SCE uses direct assignment where possible based on the nature of the expenses and accounting system limitations such as when expenses are related 100% to ISO and can be readily identified in its accounting system. This includes expenses that are directly related to ISO activities or facilities such as expenses associated with Palo Verde and Sylmar substations. Similarly, direct assignment is used for expenses where the activity or facility is clearly non-ISO such as WAPA line transmission fees.

Q. Why does not SCE use the direct assignment allocation methodology for all its assets?

A. For many expenses, it is simply not possible to directly assign to ISO or non-ISO due to the nature of the underlying O&M activity, which supports both ISO and non-ISO facilities. Therefore, an appropriate allocation methodology must be chosen.

Q. Please explain the four asset-driven allocators.

A. In choosing a reasonable allocation methodology, SCE considered methodologies used by other utilities in formula rates, the value of transparency, replicability by third parties and the Commission, and the principles of cost causation. SCE believes that the resulting allocation methodology is just and reasonable, as well readily understandable and implementable. SCE's proposed Formula Rate uses four distinct asset-driven metrics. As shown in Table 1, these metrics have been relatively stable over the 2012 – 2016 period.

Table 1
Line Miles and Circuit Breaker Count

Allocator	2012	2013	2014	2015	2016
Transmission Overhead Line Miles	48.9%	46.0%	47.2%	46.5%	46.7%
Transmission Underground Line Miles	1.7%	0.4%	0.3%	0.3%	1.4%
Transmission Circuit Breakers	34.4%	34.8%	34.8%	36.0%	36.3%
Distribution Circuit Breakers	1.8%	0.0%	0.0%	0.0%	0.0%

1. <u>Costs Allocated on the Basis of Transmission Line Miles</u>

The proposed Formula Rate uses transmission line miles to allocate the O&M costs directly related to transmission lines between ISO and Non-ISO recorded in FERC Accounts 563, 564, 567, 571, and 572. These accounts reflect the costs associated with operating and maintaining the overhead and underground transmission lines. As such, the costs in these accounts were allocated based on the overhead or underground transmission line miles. SCE believes that the allocation of the O&M expenses included in these accounts based on line miles is reasonable since it is the needs of SCE's overhead and underground transmission lines, along with the structures supporting the lines, that drive the work required to support and maintain such lines, to maintain the integrity and reliability of the system and require SCE to incur the associated O&M costs. As shown in Schedule 27, Lines 27 and 29, SCE attributes 5,660 of 12,113 (or 46.7% of total) overhead line miles and 5 of 358 (or 1.4% of total), Lines 33 and 35, underground line miles to ISO for the Prior Year. The Percent ISO Allocation Factor for overhead line miles has been relatively stable for past few years and there is no expectation of a change in this trend.

2. <u>Costs Allocated on the Basis of Circuit Breakers Numbers</u>

The proposed Formula Rate uses circuit breaker count as an overall allocator to separate O&M costs that are neither directly assigned or allocated on line miles. In particular, FERC Accounts, 560, 561, 562, 566, 568, 569, 570, 573, 582, 590, 591, and 592 record the costs that are allocated on the basis of circuit breaker counts as shown in Schedule 19. Schedule 27 reflects the fact that SCE attributes 1,184 of 3,262 (or 36.3% of total) transmission circuit breakers, Lines 39 and 41, and 0 of 8,875 (or 0% of total) distribution circuit breakers, Lines 45 and 47, to ISO for the Prior Year. SCE believes that the allocation of the non-directly assignable and non-line related Transmission and Distribution O&M expenses based on circuit breaker count is reasonable since SCE’s circuit breaker count is a reasonable proxy for the transmission and distribution facilities under the Operational Control of the ISO and the O&M expenses incurred to support those facilities. Typically, major transmission and distribution system components such as lines, transformers, capacitor banks, etc. have circuit breakers at points of interconnection into substations. The primary function of circuit breakers is to automatically isolate problems on the electric system before they can cascade into a complete system outage.

Circuit breakers perform the critical function of turning off the flow of electricity to a circuit which has encountered a problem and interrupt the flow of electricity in transmission or distribution lines. Additionally, circuit breakers are used to isolate facilities for maintenance activities. I would also note that the Percent ISO Allocation Factor for transmission circuit breakers has been relatively stable for past few years and there is no expectation of a change in this trend.

Q. What are the results of the application of the T&D O&M cost allocation methodology of Schedule 19 of SCE proposed Formula Rate?

A. SCE proposed Formula Rate uses recorded O&M expenses as input to Schedule 19 as shown on Exhibit No. SCE-4. When the proposed Formula Rate is populated with recorded 2016 information, the cost allocation methodology attributes $81.05 million in O&M expenses to ISO, Schedule 19, Line 91, Column 6. This compares to the $82.06 million under the methodology in the Original Formula Rate. Thus the results of the proposed methodology aligns with cost causation, provides greater transparency, produces a result very similar to that of the Original Formula Rate, and should prove more easily replicable by third parties.

Q. How is this allocation methodology more aligned with other Formula Rates you have reviewed.

A. In my experience with administering the current formula rate, I have found the current allocation factors, while effective in assuring a just and reasonable rate, are a bit cumbersome to implement and are not easily reproducible by reviewing parties. So, to determine if the processes put in place by the Original Formula Rate could be improved, I reviewed the formula rates of several other utilities to review the treatment of O&M allocations in their respective formula rates. In particular, I reviewed the O&M allocations used in the formulas of San Diego Gas & Electric Company, Arizona Public Service Electric Company, Pacific Corp, Baltimore Gas & Electric, Idaho Power, Midcontinent ISO, and Xcel Energy to compare methodologies. While these companies are not the only entities with formula rates, they represent a sample of industry practices in various regions of the nation.

Q. What did your review of other formula rates O&M allocators reveal?

A. The numbers of allocators used by SCE in its Original Formula Rate was significantly greater than any of the utilities examined. Typically, these utilities used only a simple plant allocation without direct ties to any specific account. As a result, SCE believed the O&M allocation methodology in the Original Formula Rate could be improved and developed its proposal to move from 17 operational allocators and 4 secondary labor allocators (plus 100% or 0%) to 4 allocators (plus 100% and 0%). This brings SCE closer to alignment with the other utilities whose Formula Rates I reviewed. Notably, SCE's proposed new allocation methodology not only reduces the number of proposed cost allocators, it continues to produce very similar results to the original methodology.

Q. Is the new proposed methodology more readily replicated by interested parties than the Original Formula Rate methodology?

A. Yes. The proposed methodology is far more formulistic and allocations are based on easily verifiable facts (circuit breakers, line miles, etc.). As a result, the new allocation methodology should be more transparent, readily subject to external verification by the Commission and the stakeholders, and easier to replicate by third parties when compared to the Original Formula Rate.

IV. DIRECTLY ASSIGNABLE EXPENSES

Q. Please describe the directly assigned transmission O&M expenses attributable to ISO Transmission.

A. There are six major categories of transmission O&M expenses that are directly assigned by the proposed Formula Rate. Within these 6 major categories, there are 12 sub-accounts the costs of which are assigned 100% to ISO O&M. There are also five sub-accounts that record costs entirely excluded from allocation to the ISO (0% to ISO). The directly assigned transmission O&M costs appear in Accounts 560, 561.4 561.5, 562, 565, 566, 567, 568, 569, 570, 571, and 572. SCE's proposed methodology for directly assignable expenses is identical to SCE's Original Formula Rate.

Q. Please describe the major categories of O&M expenses that are directly assigned to ISO O&M by the proposed Formula Rate?

A. There are four major categories of transmission O&M expenses directly assigned (100%) to ISO O&M. These four categories are as follows:

<u>Sylmar/Palo Verde (FERC Accounts 560, 562, 566, 567, 568, 569, 570, 571, and 572):</u> SCE makes payments to Los Angeles Department of Water & Power ("LADWP") and Salt River Project ("SRP") for O&M expenses related to the shared ownership of several high voltage transmission facilities where SCE has turned over its share to ISO's Operational Control. LADWP is the operating agent for the Celilo-Sylmar 1000kV DC transmission line terminating at Bonneville Power Administration's Celilo Converter Station near the border of Oregon and Washington, along with the Sylmar Converter Station located in Southern California. SRP is the operating agent for the Palo Verde Nuclear Generating Station switchyard located in central Arizona. These recorded O&M expenses are directly assigned to ISO O&M Expenses (Lines 49, 55, 63, 66, 68, 70, 72, 74, and 76 of Schedule 19).

Reliability, Planning, and Standards Development (FERC Account 561.500): This category includes the cost of SCE's Reliability Planning and Standards Development Group, which is responsible for transmission facility performance and expansion planning. This includes developing transmission performance and reliability criteria, performing transmission reliability assessments, studying load and generation interconnections, conducting post-disturbance reviews of major events, and coordination with the WECC. These recorded O&M expenses are directly assigned to ISO O&M Expenses (Line 52 of Schedule 19).

Transmission of Electricity by Others (FERC Account 565): This account includes amounts payable to others for the transmission rights over transmission facilities owned by others where SCE has placed such rights under the Operational Control of the ISO. Therefore, the expenses are directly assigned to ISO O&M Expenses. In recorded 2016, SCE recorded expenses associated with payment to Arizona Public Service ("APS") for the Four Corners to Eldorado 500kV line. This agreement, however, was terminated in 2016. Consequently, SCE anticipates the expenses in this account to be $0 in 2017 and beyond at this time (Line 58 of Schedule 19).

Eldorado (FERC Account 567): SCE pays rent to the BLM for its Eldorado-Mead No. 1 & 2 220 kV line and the Mohave-Eldorado 500 kV line. Since these lines are under the CAISO's operational control, these recorded O&M expenses are directly assigned to ISO O&M Expenses (Line 65 of Schedule 19).

Q. Please describe those transmission expenses that are excluded from ISO O&M.

A. There are two major categories of transmission O&M expenses excluded from ISO O&M (0% to ISO). These categories are:

WAPA Agreement (FERC Account 565): SCE has a transmission service agreement with the Western Area Power Administration ("WAPA") for remote service utilizing non-ISO facilities and the expenses are directly assigned to non-ISO O&M expenses. This transmission service is used to for distribution service to SCE's retail load in the vicinity of Parker California (Line 60 of Schedule 19).

Miscellaneous (FERC Accounts 561.400, 562, 565, 566): These accounts are either related to SCE's energy procurement for retail customers or are recovered through other rate mechanisms. These sub-accounts are all assigned 0% to the ISO (Lines 51, 54, 59, and 62 of Schedule 19).

Q. Are there distribution O&M accounts that directly assigned to ISO O&M?

A. Currently, there are no distribution related O&M accounts attributed to ISO (Columns 6 through 8, Line 88 of Schedule 19). SCE's proposed Formula Rate also excludes (0% to ISO) all distribution accounts with no ISO

Distribution Costs (Schedule 19, Line 86) and Distribution Non-Officer Incentive Compensation (“NOIC”) (Schedule 19, Line 87) allocated to Transmission.

V. ALLOCATED EXPENSES BASED ON APPROPRIATE METRICS

Q. You indicated earlier that certain O&M expenses were allocated between ISO and non-ISO using metric-based allocators. Please describe the metric-based allocation of O&M expenses.

A. For certain FERC T&D O&M accounts, the proposed Formula Rate utilizes four distinct asset-driven metrics to determine how to appropriately allocate O&M expenses between ISO and non-ISO. These allocators are: 1) number of ISO overhead transmission line miles as a percent of total ISO and non-ISO overhead transmission line miles; 2) number of ISO underground transmission line miles as a percent of total ISO and non-ISO underground transmission line miles; 3) number of ISO transmission circuit breakers as a percent of total ISO and non-ISO transmission circuit breakers; and 4) number of ISO distribution circuit breakers as a percent of total ISO and non-ISO distribution circuit breakers. As indicated above, this is a change in methodology from the Original Formula Rate.

Q. Could you please describe the proposed methodological changes in the metric-based allocation?

A. SCE’s new proposal for O&M allocation continues to follow with cost causation principles, is more aligned with industry practices, and is more transparent and replicable by third parties than that used in the Original Formula Rate. As such, while both the original and the proposed methodologies yield reasonable results, the new methodology does so in a manner that better conforms with industry practices and is and more amenable to third party scrutiny.

The proposed Formula Rate has 4 asset-driven metrics that will allocate 17 FERC T&D O&M Accounts between ISO and Non-ISO. This compares to 17 operational allocators and 4 secondary labor allocators to allocate 40 FERC T&D O&M Sub-accounts between ISO and non-ISO in SCE's Original Formula Rate. Table 2 below provides a mapping of how the proposed Formula Rate allocates O&M Expense compared to the Original Formula Rate on an account-by-account basis.

Table 2
Schedule 19 "Percent ISO" Allocation Factors by FERC Account

Original Formula Rate			Proposed Formula Rate		
Account/ Work Activity	**% ISO**	**% ISO Reference**	**Account/ Work Activity**	**% ISO**	**% ISO Reference**
560 – Operations Engineering	**38.1%**	**Sch 19, Note 6(a)-ISO Labor**	**560 – Operations Supervision & Engineering**	**36.3%**	**Sch 27-Circuit Breakers**
560 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**560 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
561.000 Load Dispatching	**31.4%**	**Sch 27-Outages**	**561 – Load Dispatch**	**36.3%**	**Sch 27-Circuit Breakers**
561.100 Load Dispatch-Reliability	**31.4%**				
561.200 Load Dispatch Monitor and Operate Trans. System	**31.4%**				
561.400 Scheduling, System Control and Dispatch Services	**0.0%**	**0% per Protocols**	**561.400 Scheduling, System Control and Dispatch Services**	**0.0%**	**0% per Sch 19**
561.500 Reliability, Planning and Standards Development	**100.0%**	**100% per Protocols**	**561.500 Reliability, Planning and Standards Development**	**100.0%**	**100% per Sch 19**
562 – MOGS Station Expense	**0.0%**	**0% per Protocols**	**562 – MOGS Station Expense**	**0.0%**	**0% per Sch 19**
562 – Operating Transmission Stations	**17.7%**	**Sch 27-Circuits**	**562 – Station Expenses**	**36.3%**	**Sch 27-Circuit Breakers**
562 – Routine Testing and Inspection	**20.6%**	**Sch 27-Relay Routines**			
562 – Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**562 – Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
563 – Inspect and Patrol Line	**46.7%**	**Sch 27-Line Miles**	**563 – Inspect and Patrol Line Overhead Line Expenses**	**46.7%**	**Sch 27-Line Miles**
564 – Underground Line Expense	**1.4%**	**Sch 27-UG Line Miles**	**564 – Underground Line Expenses**	**1.4%**	**Sch 27-UG Line Miles**
565 – Wheeling Costs	**0.0%**	**0% per Protocols**	**565 – Wheeling Costs**	**0.0%**	**0% per Sch 19**
565 – WAPA Trans for Remote Service	**0.0%**	**0% per Protocols**	**565 – WAPA Trans for Remote Service**	**0.0%**	**0% per Sch 19**

565 – Transmission for Four Corners	**100.0%**	**100% per Protocols**	**565 – Transmission of Electricity by Others**	**100.0%**	**100% per Sch 19**
566 – ISO/RSBA/TSP Balancing Accounts	**0.0%**	**0% per Protocols**	**566 – ISO/RSBA/TSP Balancing Accounts**	**0.0%**	**0% per Sch 19**
566 – Training	**38.1%**	**Sch 19, Note 6(a)-ISO Labor**	**566 – Miscellaneous Transmission Expenses**	**36.3%**	**Sch 27-Circuit Breakers**
566 – Other	**38.1%**				
566 – NERC/CIP Compliance	**66.0%**	**Sch 7-Plant Study**			
566- Transmission Regulatory Policy	**66.0%**				
566 - FERC Regulation & Contracts	**66.0%**				
566 - Grid Contract Management	**66.0%**				
566 - Sylmar/Palo Verde/Other General Functions	**100.0%**	**100% per Protocols**	**566 - Sylmar/Palo Verde/Other General Functions**	**100.0%**	**100% per Sch 19**
567 - Line Rents	**72.8%**	**Sch 27-Line Rents Costs**	**567 - Line Rents**	**46.7%**	**Sch 27-Line Miles**
567 - Morongo Lease	**90.8%**	**Sch 27-Morongo Acres**			
567 – Eldorado	**100.0%**	**100% per Protocols**	**567 - Eldorado**	**100.0%**	**100% per Sch 19**
567 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**567 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
568 - Maintenance Supervision and Engineering	**27.5%**	**Sch 19, Note 6(c)-ISO Labor**	**568 - Maintenance Supervision and Engineering**	**36.3%**	**Sch 27-Circuit Breakers**
568 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**568 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
569 - Maintenance of Structures	**20.3%**	**Sch 19, Note 6(b)-ISO Labor**	**569 - Maintenance of Structures**	**36.3%**	**Sch 27-Circuit Breakers**
569.100 – Hardware	**38.1%**	**Sch 19, Note 6(a)-ISO Labor**			
569.200 – Software	**38.1%**				
569.300 - Communication	**38.1%**				
569 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**569 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
570 - Maintenance of Power Transformers	**22.4%**	**Sch 27-Transformers**	**570 – Maintenance of Station Equipment**	**36.3%**	**Sch 27-Circuit Breakers**
570 - Maintenance of Transmission Circuit Breakers	**36.3%**	**Sch 27-Circuit Breakers**			
570 - Maintenance of Transmission Voltage Equipment	**67.6%**	**Sch 27-Voltage Control Equipment**			
570 - Maintenance of Miscellaneous Transmission Equipment	**27.5%**	**Sch 19, Note 6(c)-ISO Labor**			
570 - Substation Work Order Related Expense	**11.0%**	**Sch 27-Substation Work Order Cost**			
570 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**570 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
571 - Poles and Structures	**46.7%**	**Sch 27-Line Miles**	**571 – Maintenance of Overhead Lines**	**46.7%**	**Sch 27-Line Miles**
571 - Insulators and Conductors					
571 - Transmission Line Rights of Way					
571 - Transmission Work Order Related Expense	**8.1%**	**Sch 27-Trans Work Order**			

		Cost			
571 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**571 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
572 - Maintenance of Underground Transmission Lines	**1.4%**	**Sch 27-UG Line Miles**	**572 - Maintenance of Underground Lines**	**1.4%**	**Sch 27-UG Line Miles**
572 - Sylmar/Palo Verde	**100.0%**	**100% per Protocols**	**572 - Sylmar/Palo Verde**	**100.0%**	**100% per Sch 19**
573 - Provision for Property Damage Expense to Trans. Fac.	**44.1%**	**Sch 27-Trans Fac. Property Damage**	**573 - Maintenance of Miscellaneous Trans. Plant**	**36.3%**	**Sch 27-Circuit Breakers**
582 - Operation and Relay Protection of Distribution Substations	**0.00%**	**Sch 19, Note 6(d)-ISO Labor**	**582 – Station Expenses**	**0.0%**	**Sch 27-Distribution Circuit Breakers**
582 - Testing and Inspecting Distribution Substation Equipment	**0.00%**				
590 - Maintenance Supervision and Engineering	**0.00%**		**590 – Maintenance Supervision & Engineering**		
591 - Maintenance of Structures	**0.00%**		**591 – Maintenance of Structures**		
592 - Maintenance of Distribution Transformers	**0.00%**	**Sch 27-Distribution Transformers**	**592 – Maintenance of Station Equipment**		
592 - Maintenance of Distribution Circuit Breakers	**0.00%**	**Sch 27-Distribution Circuit Breakers**			
592 - Maintenance of Distribution Voltage Control Equipment	**0.00%**	**Sch 27-Distribution Voltage Control Equipment**			
592 - Maintenance of Miscellaneous Distribution Equipment	**0.00%**	**Sch 19, Note 6(d)-ISO Labor**			
Accounts with no ISO Distribution Costs	**0.00%**	**0% per Protocols**	**Accounts with no ISO Distribution Costs**	**0.0%**	**0% per Sch 19**

Q. Please explain how the proposed Formula Rate allocates T&D O&M expenses between ISO and non-ISO on an account-by-account basis?

A. I will explain the allocation for each account in turn. Note that directly assigned costs are discussed above and are not reflected in this discussion.

Q. Please describe the allocation of expenses in Account 560 – Operations Supervision and Engineering – Allocated.

A. This activity records the expenses of operations engineering, supervision of switching centers, and departmental overheads relating to management, supervision, and clerical support. Expenses include the engineering support for the operation of the transmission system in addition to the general supervision for SCE's manned switching centers.

The expenses recorded in this activity support all of the transmission functions and the proposed Formula Rate allocates these expenses based upon the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 48 of Schedule 19).

Q. Please describe the allocation of expenses in Account 561 – Load Dispatch – Allocated.

A. These accounts record expenses incurred in load dispatching operations pertaining to the transmission of electricity. Activities charged to these accounts include the directing of switching, emergency operations, curtailment of interruptible loads, load shedding, outage planning for maintenance activities, monitoring of equipment performance, and equipment control. Load dispatching activities are separated into two groups – one involving switching and the other involving system voltage control.

The expenses recorded in this activity support all of the transmission functions and the proposed Formula Rate allocates these accounts between ISO and non-ISO based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 50 of Schedule 19).

Q. Please describe the allocation of expenses in Account 562 – Station Expenses – Allocated.

A. This activity records the work performed by the Power Delivery Switching Centers to operate the electric system. This activity captures the operational costs of transmission substations and switching centers. Substation operator activities include field switching, processing line and equipment outages, and responding to interruptions of transmission circuits. This activity also records expenses relating to test crew activities in the routine testing and inspection of relays and protection schemes. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 53 of Schedule 19).

Q. Please describe the allocation of expenses in Account 563 – Overhead Line Expenses – Allocated.

A. This account records patrolmen's activities in operating field switches, patrolling overhead lines, inspecting, and if required, making the necessary repairs to overhead transmission lines. As such, the proposed Formula Rate allocates this account based on the number of ISO overhead line miles as a percentage of total transmission overhead line miles (Line 56 of Schedule 19). This is the same allocation used in the Original Formula Rate.

Q. Please describe the allocation of expenses in FERC Account 564 – Underground Lines Expenses – Allocated.

A. This account records expenses for routine patrolling, inspecting, testing of terminations, and clearing of underground transmission lines. As such, the proposed Formula Rate allocates this account based on the number of ISO underground line miles as a percentage of total transmission underground line miles(Line 57 of Schedule 19) . This is the same allocation used in the Original Formula Rate.

Q. Please describe the allocation of expenses in Account 566 – Miscellaneous Transmission Expenses – Allocated.

A. This activity records expenses related to safety programs and training, miscellaneous transmission expenses such as records and mapping costs, and miscellaneous expenses from other departments such as SCE's Operations Support for maintaining transmission and substation buildings and grounds. In addition, this activity records the costs of employees supporting growth in renewable energy and energy supply for customers throughout SCE’s service territory. Activities include negotiating and developing new contracts for interconnection, transmission, or distribution service for both generation and load projects. Activities also include oversight of the grid interconnection process (for both transmission and distribution services) from receipt of an application through signature of an interconnection or transmission agreement. Lastly, this activity records the cost of employees who administer and manage transmission, distribution and interconnection contracts or agreements after they are signed by SCE and customers. This group scans documents into a contract management system, establishes actions to be taken based on contract provisions, processes financial and tariff obligations, resolves audit and contract dispute issues, and monitors compliance with new regulations. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 61 of Schedule 19).

Q. Please describe the allocation of expenses in Account 567 – Line Rents – Allocated.

A. This activity records rents paid by SCE for use of transmission line rights-of-ways on property owned by others. This activity also records expenses associated with the Morongo lease payment. This lease results from SCE’s six existing transmission lines that currently cross tribal lands. The proposed Formula Rate allocates this account based on the number of ISO overhead line miles as a percentage of total transmission overhead line miles (Line 64 of Schedule 19).

Q. Please describe the allocation of expenses in Account 568 – Maintenance Supervision and Engineering – Allocated.

A. This activity records expenses for substation maintenance supervision, engineering and supervision by personnel from other departments, and overheads associated with management, supervision and clerical support. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 67 of Schedule 19).

Q. Please describe the allocation of expenses in Account 569 – Maintenance of Structures – Allocated.

A. This activity records expenses for the maintenance of transmission substation structures including the maintenance of heating and air conditioning systems, plumbing, lighting, and landscaping of substation structures. These costs support both substation operations and maintenance activities. This account also records the expenses incurred in: 1) the maintenance of computer hardware supporting the transmission function; 2) ongoing support for software products serving the transmission function; and 3) the maintenance of communication equipment supporting the transmission function. The proposed Formula Rate allocates this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 69 of Schedule 19).

Q. Please describe the allocation of expenses reflected in Account 570 – Maintenance of Station Equipment – Allocated.

A. This activity includes the costs associated with: 1) rebuilding and testing of transformers, replacement of deteriorated oil in transformers, and the material and labor to rebuild transformer bushings; 2) diagnostic tests and replacement or refurbishment of major components of circuit breakers; 3) maintaining and repairing transmission shunt reactors, series capacitors, condensers, and regulators; 4) maintenance of transmission substation equipment-circuit breaker, transformer, and voltage control equipment-performed by the nuclear, steam, and hydro organizations for the T&D organization; and 5) general substation maintenance to replace trench covers and other common substation facilities.

This account also records O&M expenses related to capital construction. When capital work is performed at substations to replace equipment, upgrade the infrastructure, or add new equipment to an existing facility, expenses are often incurred that are directly driven by the capital work, but do not meet capitalization criteria. Examples of capital-related O&M expenses include repairing or strengthening structures to support the additional or replaced unit, relocation of equipment (like a capacitor bank) to make space for new additions to an existing facility, switch-rack reconfiguration, and secondary wiring.

Since the maintenance recording in this activity is general in nature, it is reasonable for the proposed Formula Rate to allocate this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 71 of Schedule 19).

Q. Please describe the allocation of expenses in Account 571 – Maintenance of Overhead Lines – Allocated.

A. This activity records expenses for: 1) repairing and painting transmission line towers, poles and fixtures; 2) repairing and relocating transmission line apparatus, cleaning and washing transmission insulators, and repairing transmission line conductors; and 3) clearing rights-of-way, grading transmission line roads and trails, and trimming and removing trees along transmission lines. This activity also records O&M expenses related to capital construction. When capital work is performed to replace equipment, upgrade infrastructure or add new equipment, expenses are often incurred related to the capital work, but do not meet capitalization criteria. Examples of capital-related O&M expenses include: paving the ground when new equipment is installed, repairing or strengthening structures to support the additional or replaced unit, or relocation of equipment to make space for new additions.

Since the expenses recorded in this account support overhead transmission lines, it is reasonable for the proposed Formula Rate to allocate this account using total ISO-controlled transmission overhead line miles as a percent of total overhead transmission line miles (Line 73 of Schedule 19).

Q. Please describe the allocation of expenses in Account 572 – Maintenance of Underground Lines – Allocated.

A. This activity records expenses for cleaning and repairing of underground vaults, switch repairs and adjustments, and repair of cable splices. Since the expenses recorded in this account support underground transmission lines, it is reasonable for the proposed Formula Rate to allocate this account using total ISO-controlled transmission underground line miles as a percent of total underground transmission line miles (Line 75 of Schedule 19). This is the same allocation used in the Original Formula Rate.

Q. Please describe the allocation of expenses in Account 573 – Maintenance of Miscellaneous Transmission Plant – Allocated.

A. This account records expenses for repairing or replacing equipment damaged by adverse wind, heat, rain, lightning, earthquake, fire, and other like activities. Since the maintenance recorded in this activity is general in nature, it is reasonable for the proposed Formula Rate to allocate this account based on the number of ISO-controlled transmission circuit breakers as a percentage of the total number of transmission circuit breakers (Line 77 of Schedule 19).

Q. Please describe the allocation of expenses in Account 582 – Station Expenses.

A. This activity includes expenses of station operation, changing voltage settings of regulators, and maintaining station logs and records. This activity also records expenses for the testing and inspection of relays and protection schemes and routing testing and inspection of distribution substation equipment. The proposed Formula Rate allocates these expenses using the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Substation testing and inspecting activities are in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 82 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 590 – Maintenance Supervision & Engineering.

A. This account includes expenses incurred in the supervision of required maintenance work on the distribution system. The proposed Formula Rate allocates this account based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Supervision of substation maintenance is in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 83 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 591 – Maintenance of Structures.

A. Account 591 records expenses for the maintenance of distribution substation structures including the maintenance of heating and air conditioning systems, plumbing, lighting, and landscaping of substation structures. This account supports substation O&M activities. The proposed Formula Rate allocates this account based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers. Maintenance of substation structures is in support of distribution equipment, so it is reasonable to use the ISO distribution circuit breaker count as an allocator for this activity (Line 84 of Schedule 19). Currently there are no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Please describe the allocation of expenses in Account 592 – Maintenance of Station Equipment.

A. This activity includes the expenses associated with: 1) rebuilding and testing of transformers, replacement of deteriorated oil in transformers, and the material and labor to rebuild transformer bushings; 2) diagnostic tests and replacement or refurbishment of major components of circuit breakers; 3) maintenance and repair of transmission shunt reactors, series capacitors, condensers, and regulators; and 4) maintenance performed by the Hydro organization for the T&D organization. The activities include circuit breaker, transformer and voltage control equipment maintenance. This account also includes general substation maintenance to replace trench covers and other common substation facilities.

Since the maintenance recording in this activity is general in nature, it is reasonable for the Formula Rate to allocate expenses based on the ISO-controlled distribution circuit breaker count as a percent of total distribution circuit breakers (Line 85 of Schedule 19). Currently there is no ISO-controlled distribution circuit breakers and consequently the allocation is zero.

Q. Are there any additional expenses that are allocated between ISO O&M and non-ISO?

A. Yes, Schedule 19 also allocates Non-Officer Incentive Compensation ("NOIC") between ISO T&D and non-ISO. As discussed in the testimony of Mr. Mindess (Exhibit No. SCE-12), SCE records all incentive compensation in Administrative and General Expenses. The proposed Formula Rate splits total T&D NOIC expenses into Transmission and Distribution into based on recorded labor expenses Transmission, or Distribution, divided by total T&D labor expenses. Next, the proposed Formula Rate allocates the transmission portion of NOIC expenses between ISO and non-ISO based on the total ISO transmission labor as a percent of total transmission labor. The ISO allocation of Distribution NOIC expenses is zero in the proposed Formula Rate. This is the same allocation used in the Original Formula Rate.

Q. Does this complete your testimony?

A. Yes.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Daniel J. Allstun, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Daniel J. Allstun

> A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Daniel J. Allstun, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ALFRED L. LOPEZ

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-11)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER18-______-000**

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ALFRED L. LOPEZ

(EXHIBIT SCE-11)

Mr. Lopez's testimony provides the explanation of the Income Tax Formula used in this proposed Formula Rate proceeding to calculate Income Tax Expense included in the Prior Year TRR and True Up TRR, and the tax expense imbedded in Incremental Forecast Period TRR. Mr. Lopez also provides detailed descriptions of the components of the Income Tax Formula used in these transmission revenue requirements. In addition, Mr. Lopez provides the explanation of the formula for determining Accumulated Deferred Income Tax balances included in the calculation of FERC Rate Base. Finally, Mr. Lopez describes the components of Other Taxes reflected in the Prior Year TRR and True Up TRR.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt. No. ER18-______-000**

PREPARED DIRECT TESTIMONY OF
ALFRED L. LOPEZ
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Alfred L. Lopez, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE").

A. I am Principal Advisor, Tax at SCE. My responsibilities include managing tax related regulatory matters that come before the Federal Energy Regulatory Commission ("FERC") and the California Public Utilities Commission ("CPUC") for SCE, as well as other tax-related research and planning activities.

Q. Briefly describe your educational and professional background.

A. I hold a Master of Science in Taxation from Golden Gate University, and a Bachelor of Science Degree in Business Administration (with an emphasis in Accounting) from California State University, Los Angeles. I am a member of the California Society of CPAs and the American Institute of Certified Public Accountants, and have been employed by SCE in the Tax Department since 1989. Over the years, I have been responsible for Tax Research and Planning, Accounting for Income Taxes, and Regulatory Tax-related Matters. Prior to joining SCE, I worked in the tax and audit groups of a public accounting firm and the tax departments of two other large corporations.

Q. Have you previously submitted testimony to the Commission?

A. Yes. I have submitted testimony in SCE's transmission rate case proceedings Docket No. ER09-1534 and Docket No. ER11-3697.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of the first portion of my testimony is to provide the explanation of the Income Tax Formula used in this proposed Formula Rate proceeding to calculate Income Tax Expense included in the formula rate, as well as to provide a detailed description of the components of the Income Tax Formula. The second portion of the testimony is to provide the explanation of the Accumulated Deferred Income Tax balance reflected in Schedule 9 that is used in the calculation of the FERC Rate Base amount reflected in Schedules 1 and 4 of the formula rate. The final portion of the testimony describes the components of Other Taxes reflected in Schedule 1 of the Prior Year TRR and Schedule 4 of the True Up TRR.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the Other Taxes and Income Taxes portion of Schedule 1 (Lines 19-36 and 57-65), as well as Schedule 9 (ADIT), Schedule 25 with respect to three components of the Wholesale Difference (Taxes Deferred – Make Up Adjustment, Excess Deferred Taxes, and Taxes Deferred ACRS/MACRS, Lines 33-35), and Schedule 26 (Tax Rates).

II. INCOME TAX FORMULA

Q. Please explain the purpose of the Income Tax Formula used in the Income Tax Expense amounts reflected in Schedules 1 and 4, and embedded in Schedule 2.

A. The purpose of the Income Tax Formula is to provide a formulaic mechanism consistent with the proposed Formula Rate ratemaking approach that reflects the appropriate level of recovery of Income Tax Expense associated with SCE's transmission revenue requirement . The Income Tax Formula is included in both the Prior Year TRR and the True Up TRR, and is embedded in the Annual Fixed Charge Rate reflected in the Incremental Forecast Period TRR. The Income Tax Formula reflects the combined impact of Federal and state income tax expense associated with SCE's transmission revenue requirement.

Q. Please provide a description of the Income Tax Formula.

A. The Income Tax Formula is as follows:

$$\text{Income Tax Expense} = [((RB * ER) + D) * (CTR/(1 - CTR))] + CO/(1 - CTR)$$

Where:

RB = Rate Base

ER = Equity Rate of Return that includes Common and Preferred Stock

D = Book Depreciation of AFUDC-Equity Book Basis

CTR = Composite Tax Rate

CO = Tax Credits and Other

The Income Tax Expense, as calculated pursuant to the Income Tax Formula, represents the combination of the following components: 1) the Federal and state income tax expense associated with SCE's recovery of equity rate-of-return on rate base (that includes common and preferred stock), grossed-up to a revenue requirement; 2) the Federal and state income tax expense on the recovery of book depreciation associated with AFUDC-Equity book basis, grossed-up to a revenue requirement; and 3) tax credits and other tax adjustments, grossed-up to a revenue requirement.

For the first component of the Income Tax Formula, rate base is multiplied by the equity rate of return percentage, with the resulting product multiplied by the tax gross-up factor to derive the required revenue for this tax component. The tax gross-up factor is equal to the Composite Tax Rate divided by one minus the Composite Rate. The Composite Tax Rate is equal to the Federal statutory income tax rate plus the product of the state apportioned income tax rate times one minus the Federal statutory income tax rate. The Federal income tax rate is reflected in Line 1 of Schedule 26. The state income tax rate is reflected in Line 8 of Schedule 26. The Composite Tax Rate is reflected in Line 59 of Schedule 1.

For the second component of the Income Tax Formula, the recovery of book depreciation associated with the capitalized AFUDC-Equity amount included in book basis is multiplied by the tax gross-up factor to derive the revenue requirement for this tax component. The recovery of this tax gross-up is necessary because capitalized AFUDC-Equity amounts included in book basis and subsequently recovered through book depreciation expense is a ratemaking construct that has no equivalent for tax purposes. Thus, when revenue is received for book depreciation associated with the AFUDC-Equity basis, there is no offsetting tax basis to depreciate for tax purposes, which results in additional taxable income and additional income tax expense that must be recovered in rates.

For the third component of the Income Tax Formula, tax credits and other adjustments to tax are divided by one minus the Composite Tax Rate to derive the appropriate grossed-up revenue requirement for this tax component.

Q. Are the factors in the Income Tax Formula used in this proposed Formula Rate proceeding the same as those used in the Income Tax Formula in the Original Formula Rate?

A. Yes, the factors (*i.e.*, RB, ER, D, CTR and CO) in the Income Tax Formula used in this proposed Formula Rate proceeding are the same as those used in the Income Tax Formula in the Original Formula Rate. However, the CTR factor in this proposed Formula Rate includes only Federal and apportioned California income tax rates whereas the CTR in the Original Formula Rate included Federal and apportioned California, Arizona, New Mexico and D.C. income tax rates.

Arizona is no longer included in determining the CTR because SCE elects an Arizona apportionment method that effectively excludes taxes from this state. New Mexico is no longer included in determining the CTR because SCE no longer maintains a material presence in this state, and D.C. is excluded because it is immaterial.

In addition, although the CO (Tax Credits and Other) amounts in this proceeding will be the same as in the Original Formula Rate, they will be subject to changes in the future when they are fully amortized. See below for detailed descriptions of the CO's and the explanations for any changes.

Q. Please provide a description of the Credits and Other Tax Items.

A. Credits and Other Tax Adjustments included in the Income Tax Formula reflected in Schedule 1 and Schedule 4 consist of the following three items:

1) Amortization of Excess Deferred Tax Liability; 2) Amortization of the Investment Tax Credit; and 3) Amortization of the South Georgia Income Tax Adjustment. The amortization amounts for each of these three items are reflected in Lines 60 through 62 of Schedule 1, and Line 25 of Schedule 4.

Q. Please explain the Amortization of Excess Deferred Tax Liability.

A. The Amortization of Excess Deferred Tax Liability, as reflected in Line 60 of Schedule 1, represents the adjustment to income tax expense resulting from legislative changes to statutory corporate income tax rates. Section 203(e) of the Tax Reform Act of 1986 required excess deferred tax amounts as a result of these legislative changes to be subject to the normalization requirements. Under the tax normalization rules, the fixed annual amount of $200 for retail customers associated with the change in corporate tax rates is amortized over a 27-year period that will end after the year 2024.

For wholesale customers, the fixed annual Amortization of Excess Deferred Tax Liability of $42,900 is effectuated with an adjustment to retail amortization rates of $43,100 as reflected in Line 21 of Schedule 25.

The Amortization of Excess Deferred Tax Liability for retail and wholesale customers is the same as Original Formula Rate as well as SCE’s other pre-formula FERC stated rate case proceedings.

Q. Please explain the Amortization of Investment Tax Credit.

A. The Amortization of Investment Tax Credit for retail and wholesale customers of $520,000, as reflected in Line 61 of Schedule 1, represents the reduction of income tax expense for the remaining deferred investment tax credit balance that is being amortized over the book life of the related property as required by Internal Revenue Code Section 46(f)(2) prior to its repeal. Under the tax normalization rules, the fixed annual amount of $520,000 associated with the amortization of investment tax credit will end after the year 2018. For 2019, the Amortization of Investment Tax Credit will be $183,000, and then will be zero thereafter. Since this amortization is changing in the 2019 year, SCE is proposing to make this amount a "yellow-shaded input" in the proposed Formula Spreadsheet, and include the amounts that will be effective for each year in new Note 3 of Schedule 1. The Amortization of Investment Tax Credit is the same as SCE's Original Formula Rate, as well as SCE's other, pre-formula, FERC stated rate proceedings.

Q. Please explain the Amortization of the South Georgia Income Tax Adjustment.

A. The Amortization of the South Georgia Income Tax Adjustment represents the recovery of tax benefits previously flowed through to customers in prior regulatory proceedings.

For retail customers, the fixed annual South Georgia Income Tax Adjustment of $2,606,000, as reflected in Line 62 of Schedule 1, represents the recovery of income tax benefits previously flowed-through to retail customers prior to the regulatory transition of retail transmission revenue requirement proceedings from the California Public Utilities Commission ("CPUC") jurisdiction to FERC jurisdiction in March 1998. Under prior CPUC jurisdiction, retail customers were provided with flow-through tax accounting treatment for certain book/tax differences, such as state tax depreciation differences and Federal tax depreciation differences on pre-1981 assets, that were subsequently required under FERC jurisdiction to be accorded full normalization tax accounting treatment. The South Georgia Income Tax

Adjustment is designed to recover those previously flowed-through tax benefits that would not otherwise be recovered under the fully normalized ratemaking tax accounting treatment. The fixed annual South Georgia Income Tax Adjustment of $2,606,000 is amortized over a 27-year period that will end after the year 2024. The retail Amortization of the South Georgia Income Tax Adjustment is consistent with SCE's Original Formula Rate, as well as SCE's other pre-formula FERC stated rate proceedings.

For wholesale customers, the fixed annual South Georgia Income Tax Adjustment amortization amount of $103,000 represents SCE's recovery of income tax benefits previously flowed-through to wholesale customers prior to FERC's implementation to full normalization. The difference of $2,503,000 between wholesale and retail amortization of the South Georgia Income Tax Adjustment is reflected in Line 8 of Schedule 25. This fixed annual South Georgia Income Tax Adjustment is amortized over a 27-year period that will end after the year 2024. The wholesale Amortization of the South Georgia Income Tax Adjustment is the same as SCE's Original Formula Rate proceeding as well as SCE's other pre-formula FERC stated rate proceedings.

Q. Please explain the ACRS/MACRS Deferred Tax Adjustment used in the Calculation of the Wholesale Differences to Base TRR.

A. The ACRS/MACRS Deferred Tax Adjustment balance represents the differences in the retail and wholesale amounts of the ACRS/MACRS deferred tax adjustment balances resulting from the regulatory transition of retail transmission revenue requirement proceedings from the CPUC jurisdiction to FERC jurisdiction in March 1998, calculated on an average of BOY and EOY basis. This difference is shown on Line 10, Column 1 of Schedule 25, and the associated annual amortization adjustment is shown on Line 10, Column 2. This fixed annual ACRS/MACRS Deferred Tax Adjustment is amortized over a 27-year period that will end after the year 2024.

Q. What is the amount of Income Taxes in Prior Year TRR?

A. The Income Tax Amount in Prior Year TRR is $230,428,899.

III. ACCUMULATED DEFERRED INCOME TAX

Q. What is Accumulated Deferred Income Tax?

A. Accumulated Deferred Income Tax ("ADIT") represents the tax effect on the accumulated temporary difference between the tax basis of an asset or liability and its reported amount in the financial statements that will result in taxable income or deduction amounts in future years when the reported amount of the asset is recovered or the liability is settled.

Q. What are the general implications of ADIT on Rate Base?

A. FERC-related ADIT balances are used to adjust rate base in the computations of Base TRR and True Up TRR. If the tax basis of an asset is less than its amount reported in the financial statements or if the tax basis of a liability is greater than its amount reported in the financial statement, then the ADIT will have a liability (*i.e.*, credit) balance that will reduce rate base. If the tax basis of an asset is greater than its amount reported in the financial statements or if the tax basis of a liability is less than its amount reported in the financial statements, then the inverse will occur and the ADIT will have an asset (i.e., debit) balance that will increase rate base.

Q. Does SCE's FERC Form 1 provide information on ADIT balances?

A. Yes. SCE's FERC Form 1 includes year-end ADIT balances in FERC accounts 190, 282 and 283 that are used in the Formula Rate proceedings to calculate the

ADIT adjustment to rate base as reflected in Line 13 of Schedule 1 and Line 13 of Schedule 4. FERC Account 190 ADIT represent asset balances and are reflected on page 234 of the FERC Form 1. FERC Account 282 ADIT represent liability balances and are reflected on pages 274-275, and Account 283 represent liability balances and are reflected on pages 276-277 of the FERC Form 1.

Q. How does the proposed Formula Rate determine the ADIT adjustment to Rate Base?

A. Schedule 9 of the proposed Formula Rate separately examines each recorded ADIT subaccount balance of FERC Accounts 190, 282 and 283 to determine the amount attributable to ISO transmission and distribution that should be included in the ADIT adjustment to FERC Rate Base. In Schedule 9, each line-item ADIT subaccount 190, 282 and 283 balances are identified with costs that are either (1) subject entirely to recovery from a regulatory jurisdiction or proceeding other than through this formula rate proceeding, (2) subject entirely to recovery through this formula rate proceeding, (3) shared costs that relate primarily to property, or (4) shared costs that relate primarily to labor.

ADIT subaccount balances that are identified with costs that are subject entirely to recovery from regulatory jurisdictions or proceedings other than this formula rate proceeding are excluded entirely from any impact to the ADIT component of FERC Rate Base in this formula proceeding. ADIT subaccount balances that are identified with costs that are subject entirely to recovery in this formula rate proceeding are included in their entirety in the ADIT component of FERC Rate Base. ADIT subaccount balances that are identified with costs that are shared costs that relate primarily to property are first reduced for the property-related allocated percentage attributable to non-electric operations as reflected in Instruction 2 before the remaining balances are allocated to ADIT in the formula rate based on the Transmission Plant Allocation Factor percentage as reflected in Schedule 27, Line 22. ADIT subaccount balances that are identified with costs that are shared costs that relate primarily to labor are first reduced for the labor-related allocated percentage attributable to non-electric operations as reflected in Instruction 2 before the remaining balances are allocated to ADIT in the formula rate based on the Transmission Wages & Salaries Allocation Factor percentage as reflected in Schedule 27, Line 9.

Q. Where in the formula rate are these calculations shown?

A. FERC Account 190 ADIT is calculated on Lines 100 to 353 of Schedule 9, and the total FERC-related account 190 ADIT adjustment to rate base is presented on Line 354 of Schedule 9. Account 282 ADIT is calculated on Lines 400 to 452 of Schedule 9, and the total FERC-related account 282 ADIT adjustment to rate base is presented on Line 453 of Schedule 9. Account 283 ADIT is calculated on Lines 500 to 803 of Schedule 9, and the total FERC-related account 283 ADIT adjustment to rate base is presented on Line 804 of Schedule 9.

Q. Are there adjustments to Rate Base that are attributable to Deferred Investment Tax Credit balances?

A. No. Under the tax normalization rules, SCE is required to treat deferred investment tax credits consistent with section 46(f)(2) of the Internal Revenue Code, prior to its repeal. Pursuant to section 46(f)(2), investment tax credits are to be initially deferred and subsequently amortized over the remaining book life of the property (as previously described in this testimony), and the deferred investment tax credit balances are not to be included in the adjustment to rate base.

Q. Are there adjustments to the ADIT component of Rate Base that are attributable to deferred taxes that cannot be currently used by SCE?

A. Yes. SCE adjusts the ADIT component of Rate Base consistent with SCE's Private Letter Ruling ("PLR") 201438003 issued by the Internal Revenue Service ("Service") for deferred taxes that cannot be currently used by SCE. In this PLR, the Service concluded that it would be inconsistent with the tax normalization requirements for SCE to reduce rate base by the full ADIT liability balance without reducing that full ADIT liability balance by the deferred tax asset attributable to a net operating loss carryover amount that represents tax benefits that cannot be utilized because of the resulting elimination of taxable income. When applicable, this adjustment is reflected in Line 116 of Schedule 9.

Q. Are the factors in computing the ADIT adjustment to Rate Base the same as those used in SCE's Original Formula Rate?

A. Yes, the factors used in computing the ADIT adjustment to Rate Base in this proposed Formula Rate proceeding are the same as those used in SCE's Original Formula Rate.

Q. Are the computations of ADIT the same as those used in SCE's Original Formula Rate?

A. The computation of the average FERC-related ADIT balance on Line 4, Column 2 of Schedule 9 is the same as those used in SCE's Original Formula Rate. The computation of the average FERC-related ADIT balance on Line 14, Column 2 of Schedule 9 has changed from those used in SCE's Original Formula Rate.

The adjustment to rate base for the True Up TRR will now be calculated under the pro rata weighed average method consistent with the normalization rules instead of the simple average method used in the Original Formula Rate. This pro rata weighted average methodology is in response to recent rulings issued by the Service regarding the calculation of ADIT used to adjust rate base in the Formula Rate proceedings. Also, the pro rata weighted average method used in this proceeding is consistent with the method used by SCE in its CPUC General Rate Case proceedings. The pro rata computation is reflected and described in Lines 805 through 819 of Schedule 9 consistent with Treasury Regulations Section 1.167(l)-6(h)(6), PLRs 201717008, 201532018, 9313008, 9202029 and 9224040. In addition, since SCE is proposing to recover all incentive compensation expenses in this proposed Formula Rate, as described in the testimony of Mr. Mindess, Exhibit No. SCE-12, the allocation factor used for Executive Compensation ADIT amounts reflected in Lines 101 & 103, Column 6 of Schedule 9 of the populated Formula Rate Spreadsheet (Exhibit No. SCE-4), are not reduced by 50 percent as the equivalent line items were under the Original Formula Rate.

Q. What is the ADIT amount used to adjust rate base in the Prior Year TRR?

A. The ADIT balance used to adjust Rate Base in the Prior Year TRR is $1,550,608,605.

IV. OTHER TAXES

Q. Please describe the Other Taxes component of the Prior Year TRR and True Up TRR.

A. Other Taxes are the sum of FERC-related Payroll Tax Expense and Property Tax Expense that are calculated in Schedule 1, Lines 19 to 36. Payroll Tax

Expense is an allocated portion of Total Electric Payroll Tax Expense using the W&S AF, in accordance with Commission policy. The formula rate reduces Total Electric Tax Expense by SCE's capitalized overhead amount before applying the W&S AF, to reflect the fact that SCE capitalizes a portion of the Electric Payroll Tax Expense stated in FERC Form 1. Property Taxes are an allocated portion of Total Property Taxes, using the Transmission Plant Allocation Factor. Total Electric Payroll Tax Expense and Total Property Tax Expense are the company total amounts reflected in FERC Form 1, both in Account 408.11.

Q. What is the amount of Other Taxes in Prior Year TRR?

A. The amount of Other Taxes in Prior Year TRR is $58,568,952.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Alfred L. Lopez, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Alfred L. Lopez

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Alfred L. Lopez, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission #
My Comm. Exp.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ROBERT G. MINDESS

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-12)

OCTOBER 27, 2017

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ROBERT G. MINDESS

(EXHIBIT SCE-12)

Mr. Mindess's testimony provides a detailed description of SCE's treatment of its Administrative & General Expense ("A&G Expense"), as well as its Franchise Fees Expense and Uncollectibles Expense, in its proposed Formula Rate. Mr. Mindess describes generally what A&G Expense consists of, how the proposed Formula Rate will recover A&G Expense based chiefly on a labor allocation factor and partly based upon a plant allocation factor (for recovery of property insurance costs) in accordance with Commission policy, and will discuss what adjustments are made to SCE's A&G Expense amounts reported in its annual FERC Form 1 filing with the Commission. Mr. Mindess will discuss the various incentive compensation plans and recognition programs at SCE, how they are accounted for, and how they are recovered in the proposed Formula Rate. Mr. Mindess will also discuss what its proposed Formula Rate's A&G Expense, Franchise Fees Expense and Uncollectibles Expense schedule filed as part of SCE's Formula Rate annual update filings will contain, as well as what supporting workpapers will accompany SCE's annual rate filings. Finally, Mr. Mindess will describe how the proposed Formula Rate differs from the Original Formula Rate with respect to certain aspects of its A&G Expense recovery.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ROBERT G. MINDESS
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Robert G. Mindess, and my business address is 8631 Rush Street, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Project Manager in the FERC Rates and Market Integration Division within Edison's Regulatory Affairs Department. My primary responsibilities include development of rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC"), and reviewing FERC-jurisdictional contracts to make sure they comply with current FERC policy.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts Degree in biology from the University of Colorado at Boulder, Colorado, and a Juris Doctor Degree from the Whittier College School of Law in Los Angeles, California. I have been a member of the California and Washington D.C. bars since 1993. I have been employed at SCE since 2007 in various positions, including Contract Manager and Project Manager, and have been in my present role since April 22, 2013.

Q. Have you submitted testimony to the Commission previously?

A. No.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to describe the details of SCE's proposed determination of Administrative & General Expense ("A&G Expense"), its Franchise Fees Expense, and its Uncollectibles Expense ("FF & U Expense) within its proposed Formula Rate to become effective January 1, 2018, for the setting of its transmission rates under SCE's Transmission Owner Tariff, FERC Electric Tariff, Volume No. 6.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 20 (A&G) and Schedule 28 (FF&U).

II. OVERVIEW OF SCE'S A&G EXPENSE

Q. Please describe the Administrative and General Expense component of the proposed Formula Rate.

A. A&G Expense represents the costs of SCE's administrative and general corporate expenses, which are expenses that support the operation of the entire company. A portion of the A&G Expense is then allocated to the ISO transmission function and recovered through the Base Transmission Revenue Requirement ("Base TRR").

A&G Expense is calculated by applying allocation factors[1] to amounts recorded in the A&G accounts (Accounts 920-931 and 935). From these amounts,

1 *See* Sections VI and VII of the testimony of Antonio Ocegueda (Exhibit No. SCE-15) for an explanation of the Wages and Salaries and Plant Allocation Factors used in allocating total SCE A&G expenses to the ISO Transmission A&G Expenses recovered through the proposed Formula Rate.

certain costs are excluded for various reasons which are described in greater detail below. The remaining cost amounts are allocated to the Prior Year TRR using the Transmission Wages and Salaries Allocation Factor ("Labor Allocator") for most accounts. In the attached proposed Formula Rate (Exhibit No. SCE-4) filed concurrently with this testimony, the Labor Allocator is 6.1650% (*see* Schedule 20, Line 19). The exception is that Account 924 (Property Insurance) expenses are allocated using the Transmission Plant Allocation Factor ("Plant Allocator") in accordance with Commission policy. In the attached proposed Formula Rate (Exhibit No. SCE-4), the Plant Allocator is 19.3143% (*see* Schedule 20, Line 21). As such, the Property Insurance Portion of A&G Expense is $2,728,124 (which is calculated as 19.3143% times $14,124,920). (*See* Schedule 20, Line 22.)

Q. Are there any cost categories that are excluded from the recorded FERC Form 1 A&G accounts in SCE's determination of its A&G Expense amount?

A. Yes. Certain costs are excluded from the recorded FERC Form 1 A&G accounts because they are: (1) paid for by SCE's shareholders; (2) franchise requirement costs in Account 927; (3) certain advertising costs in Account 930.1; (4) expenses that are covered 100% under California Public Utilities Commission rates; (5) certain Miscellaneous General Expenses in Account 930.2; and (6) certain post-retirement benefits other than pensions ("PBOPs") which are different than the specific amount authorized by the Commission.

Q. Why are shareholder costs excluded from the recorded FERC Form 1 A&G accounts?

A. Shareholder costs are amounts that SCE has spent during the year on behalf of SCE's shareholders and that do not benefit SCE's ratepayers, and are therefore not included for recovery from SCE's ratepayers. An example of such a shareholder cost is the expense amount for costs incurred to pay for the labor and other costs associated with the operation of an employee fitness center facility located at

SCE's General Office Complex in Rosemead, California. These costs are excluded and are paid entirely by SCE's shareholders.

Q. Why are franchise requirement costs that are recorded in Account 927 excluded from the recorded FERC Form 1 A&G accounts?

A. Franchise Requirements costs are excluded because the proposed Formula Rate does not recover Franchise Requirements costs through its A&G Expense, but instead recovers these costs through another component of the Base TRR, and this will be explained in detail later in Section III of this testimony.

Q. Why are certain General Advertising Expenses that are recorded in Account 930.1 excluded from the recorded FERC Form 1 A&G accounts?

A. Pursuant to Commission policy and its clarification through the *PATH* decision,[2] any costs in Account 930.1 (General Advertising Expense) that are related to advertising for civic, political and related activities, such as those designed to solicit public support or the support of public officials in matters of a political nature are excluded from the proposed Formula Rate. As such, SCE's proposed Formula Rate seeks to only recover general advertising expenses that are for safety, siting, or of an informational nature through this proposed Formula Rate, in the same manner as the Original Formula Rate.

Q. Why are certain Miscellaneous General Expense amounts that are recorded in Account 930.2 excluded from the recorded FERC Form 1 A&G accounts?

A. Account 930.2 contains expenses that are incurred in the general management of the company that are not provided for elsewhere. In SCE's Original Formula Rate, certain specific costs recorded in Account 930.2 were excluded from transmission rates. SCE will continue this practice and not seek to recover certain

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2 *See Potomac-Appalachian Transmission Highline, LLC and PJM Interconnection*, LLC, 152 FERC ¶ 63,025 (2015), and FERC Docket Nos. ER09-1256-002 and ER12-2708-003.

miscellaneous general expense amounts through the proposed Formula Rate in accordance with Instruction 2 of Schedule 20 of Exhibit No. SCE-4. The specific items of excluded expenses that SCE will continue to exclude are: Provision for Doubtful Accounts – Non-Energy Billings; accounting suspense amounts; balance sheet write-offs of abandoned project expenses; nuclear power research expenses; annual report preparation expenses noted under "Pub & Dist Info to Stkhldrs"; other experimental and general research expenses that are not charged to other operation and maintenance expense accounts on a functional basis; any penalties or fines; and any costs recovered 100% through California Public Utilities Commission rates.

Q. Why are certain Post-Retirement Benefits Other Than Pensions ("PBOPs") amounts recorded in Account 926, which are different that the specific amount authorized by the Commission, excluded from the recorded FERC Form 1 A&G accounts?

A. PBOPs Expense are those costs that SCE incurs for providing post-retirement medical, dental and vision coverage, Medicare Part B premium reimbursement and term life insurance coverage to its retirees. Pursuant to current Commission policy as noted in *Maine Yankee,*[3] a formula rate shall state a specific authorized amount of PBOPs Expense that a utility may recover each year. Accordingly, any difference between the actual PBOPs expense incurred during a year that is

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[3] *See Maine Yankee Atomic Power Company*, 43 FERC ¶ 61,453, at 61,923 (1988) (Commission policy requires PBOPs and Depreciation Rates to be specified, even if the utility operates under a formula rate. This is because PBOPs is amortized PBOP accounts are typically amounts that are amortized over a set period of time much like depreciation or decommissioning expenses. A modification in the amortization without Commission scrutiny can result in over-recovery or intergenerational inequities. A stated amount is needed to provide specificity in the calculation of formula rate, as it appears in the form of a rate schedule.).

included in Account 926, and the Commission-approved amount of stated PBOPs Expense reflected in the formula rate is excluded from recovery. In the proposed Formula Rate, the initial amount of Authorized PBOPs Expense Amount is $40,171,333. (*See* Protocols, Section 8. b.) This amount, however, may change in either a positive or negative direction, but only if SCE makes a single-issue Federal Power Act Section 205 ("FPA 205") filing to the Commission requesting a new stated Authorized PBOPs Expense Amount, and the Commission approves the filing.

Q. Why has Note 3 in Schedule 20 been revised in the proposed Formula Rate Spreadsheet?

A. SCE is proposing to change Note 3 to show the Prior Year Authorized Expense Amount so that the adjustment which used to go in Schedule 4 is made in Schedule 20 of Exhibit No. SCE-4 instead. This will serve to simplify the PBOPs mechanism and ensure that the PBOPs expense component of the True Up TRR is based on the Authorized PBOPs Expense Amount that was in effect during the Prior Year.

Q. Do SCE employees have a component of their compensation that is based upon company performance?

A. Yes. Under SCE's Short-Term Incentive Plan ("STIP"), eligible employees have compensation opportunities that are market competitive and are intended to fairly compensate them for meaningful contributions to the Company's strategic business objectives of safely delivering reliable and affordable electricity to its customers. The amount an employee receives under STIP is a component of Non-Officer Incentive Compensation ("NOIC") in SCE's proposed Formula Rate. NOIC also includes the Augmented Bonus plan. This plan provides principal level employees and senior attorneys (who are not eligible for the Long Term Incentive plan) with compensation opportunities based upon their impact to mid to long term results of the Company, and is used by SCE as a way to retain employees with a history of strong performance, critical skills and great future potential. The third component of NOIC is the Non-Officer Executive Incentive Compensation Plan. This plan provides executive employees that are not officers of SCE, with a competitive compensation for their contributions to the goals and objectives of the Company.

Q. How does SCE account for NOIC?

A. NOIC expenses represent total company employee incentive payments that are recorded to Account 920 on an accrued basis in FERC Form 1. SCE initially accrues its NOIC expenses with the expectation that it will be fully paid out to employees and therefore reserves the total amount that could be owed under NOIC. As such, during the year, SCE accrues and records on its books for a 100% or full NOIC payout based upon the sum of all target awards for all participants following the conclusion of the annual performance period (from January 1st through December 31st). The Compensation Committee of SCE's Board of Directors determines Company performance (referred to as the corporate modifier) following the end of the plan year. Each employee's NOIC payout equals the target award for their position, adjusted by the corporate modifier for exempt employees. SCE adjusts its books to show that amount of approved NOIC, which will be that amount ultimately paid out to SCE's eligible employees in March after the end of the plan year. The amount of NOIC recorded in SCE's ledgers will have two components, a capitalized portion and a non-capitalized portion. The capitalized portion is included in workorders and ultimately is recorded to plant and included in SCE's rate base. That capitalized amount is then deducted from the total amount of approved NOIC to be paid out. The remaining non-capitalized amount of NOIC will be recovered through the proposed Formula Rate within the A&G Schedule as allocated amount based upon the Labor Allocator (6.1650%).

Q. Describe the cash and non-cash recognition programs at SCE that are available to employees, and discuss how SCE proposes to treat recognition pay in its proposed Formula Rate?

A. SCE's recognition programs acknowledge employees for desired behaviors, such as achieving exceptional business results. SCE's cash and non-cash recognition programs are known as Spot Bonus and Awards to Celebrate Excellence ("ACE"), respectively.

The Spot Bonus program recognizes an individual or a team for delivering exceptional, measurable results, making significant contributions, developing a new or innovative program or process, or leading a Company-wide team or major project that notably exceeds expectations, within scheduled time frames and comes in under budget, which also leads to reduced expenses and ultimately, lower rates for SCE's customers. Spot Bonuses are also used to provide real-time rewards for those employees who accept and perform additional responsibilities in an exceptional manner or accept responsibilities or assignments that require extraordinary time commitments.

ACE uses points to award employees for promoting a safe working environment through their actions and behaviors, and for helping contribute to public safety. All non-executive employees are eligible to participate in this program.

Q. Do SCE executive officers have a component of their compensation that is based upon company performance?

A. Yes. Executive officers have an incentive pay plan that is tied to overall company performance. This plan is known as the Executive Incentive Compensation Plan ("EIC") and is referred to in SCE's proposed Formula Rate as the Officer Executive Incentive Compensation ("OEIC"). The EIC plan is part of the market competitive compensation package designed to attract and retain a well-qualified leadership team which best serves the needs of SCE's customers.

Q. How does SCE account for and recover OEIC?

A. For purposes of recovery of OEIC under SCE's proposed Formula Rate, it is treated in the same manner as NOIC in that there will be an accrued amount of OEIC shown on SCE's ledgers, which is then adjusted to reflect the actual amount of OEIC as determined by SCE's Board of Directors. Further, there are capitalized and non-capitalized portions of OEIC, which is handled for recovery purposes in the same manner as that described above for NOIC.

Q. Does SCE have a long term incentive pay mechanism?

A. Yes. SCE also has another variable component of executive employees' compensation known as the Long Term Incentive Plan ("LTI"). LTI includes non-qualified stock options, restricted stock units, and performance shares, with multi-year vesting periods from three to four years. LTI is dependent upon a number of factors including multiple years of continuous employment, strong job performance at the executive level, and financial health of the Company. LTI grants are provided as a means to incentivize executives to conduct themselves and to make decisions which lead to safer and more reliable service and to encourage the development of just and reasonable electrical rates which inures to the benefit of SCE's ratepayers. As such, LTI grants are properly recoverable in SCE's transmission rates.

Q. Describe SCE's Executive Retirement Plan.

A. SCE executives are eligible for its non-qualified pension plan known as the Executive Retirement Plan ("ERP") (which is known as the Supplemental Executive Retirement Plan ("SERP") in SCE's proposed Formula Rate). The SERP provides benefits that executives cannot receive from the qualified SCE Retirement Plan due to compensation and payout limits imposed by the Internal Revenue Code on that plan. The compensation recognized for plan purposes is base pay, except for elected officers, where compensation is base pay plus bonus. In the proposed Formula Rate, SCE will incur $16,235,328 in SERP Expense (*see* attached Schedule 20 Workpaper, Line 1, Calculation of SERP Expense, Page 5 of 10 of Exhibit No. SCE-22).

III. OVERVIEW OF FRANCHISE FEES AND UNCOLLECTIBLE EXPENSES

Q. Please describe the Franchise Fees component of the Prior Year TRR.

A. Franchise Fees represent the payments that SCE makes to municipal entities for the right to locate its electric facilities within the municipality. The proposed Formula Rate determines Franchise Fees Expense by applying the Franchise Fee Factor, as approved by the California Public Utilities Commission ("CPUC"), to the components of the Base TRR, including the Prior Year TRR calculated on Schedule 1 (Line 79), the Incremental Forecast Period TRR calculated on Schedule 2 (Line 79), and the True Up TRR calculated on Schedule 4 (Lines 42-43). In the proposed Formula Rate, the Franchise Fees allocation factor is 0.92057% (*see* Exhibit No. SCE-4, Schedule 28, Line 5) and the total amount of Franchise Fees Expense is $10,006,372 (See Exhibit No. SCE-4, Schedule 1, Line 79). The Wholesale Difference to the Base TRR includes the amount of Franchise Fees Expense included in the Base TRR as a reduction that will reduce the Wholesale Base TRR (Exhibit No. SCE-4, Schedule 25, Line 44).

Q. Please describe the Uncollectibles component of the Prior Year TRR.

A. The proposed Formula Rate determines Uncollectibles Expense by applying the CPUC-approved Uncollectibles Expense Factor to the total of the above-mentioned Base TRR components. In the proposed Formula Rate, the Uncollectibles Expense allocation factor is 0.24076% (*see* Exhibit No. SCE-4, Schedule 28, Line 5), and the total amount of Uncollectibles Expense is $2,617,003 (*see* Exhibit No. SCE-4, Schedule 1, Line 80). The proposed Formula Rate determines Uncollectibles Expense by applying the Uncollectibles Factor, as approved by the California Public Utilities Commission ("CPUC"), to the components of the Base TRR, including the Prior Year TRR calculated on Schedule 1 (Line 80), the Incremental Forecast Period TRR calculated on Schedule 2 (Line 80), and the True UP TRR calculated on Schedule 4 (Lines 44-45) of Exhibit No. SCE-4.

Q. Why is Uncollectible Expense excluded from the Wholesale Base TRR?

A. Uncollectibles Expenses represent billed retail revenue that SCE does not collect. Uncollectible Expense is included in SCE's retail Base TRR through an addition of an amount based on the Uncollectible Expense Factor as a last step once all other components to the Base TRR are calculated. However, Uncollectibles Expense represents amounts charged to retail customers but not ultimately collected. Accordingly, it is inappropriate to include it as a component of the Wholesale Base TRR. The Wholesale Difference to the Base TRR includes the amount of Uncollectibles Expense included in the Base TRR as a reduction that will reduce the Wholesale Base TRR (Exhibit No. SCE-4, Schedule 25, Lines 41 and 42).

Q. Does SCE propose any changes in its recovery of Franchise Fees Expense and Uncollectible Expense in the attached proposed Formula Rate or protocols at this time?

A. No. The proposed Formula Rate schedule and protocols are unchanged. Only the inputs will be updated when the CPUC authorizes new factors. These factors are reviewed every three years in SCE's CPUC General Rate Case. SCE identifies the revision of FF&U factors as a "single issue" adjustment pursuant to the proposed Protocols.

IV. FORMAT OF THE SCHEDULE AND WORKPAPERS FOR A&G EXPENSE

Q. Please describe the Format of Schedule 20-A&G of the Formula Rate spreadsheet.

A. Schedule 20 of the Formula Rate Spreadsheet (Exhibit No. SCE-4) is the schedule that calculates A&G Expense in SCE's proposed Formula Rate. Items that are inputs to the Formula Rate Spreadsheet are shaded yellow. These yellow-shaded cells are the only parts of the Formula Rate Spreadsheet that SCE may revise each year during its Annual Update filing process. The source of each ultimate input is tied to SCE's FERC Form 1 filing, or, when specifically noted, to SCE's internal records. The amounts and associated calculations that are contained within Schedule 20 come from the workpaper for Schedule 20 contained within Exhibit No. SCE-22.

Schedule 20 shows the total A&G Expense broken down into its component FERC Accounts, and the amounts excluded from SCE's FERC Form 1 filing for accounts 920-935. Then further deductions and exclusions are made so that the amount of SCE's A&G Expenses are shown. The Schedule's Notes show the itemization of exclusions, the NOIC Adjustment, and the PBOPs Exclusion Calculation.

In the proposed Formula Rate, that amount of A&G expense to be included for recovery in the Base TRR for 2018 is $52,426,004 (See Exhibit No. SCE-4,Schedule 20, Line 23).

Q. Please describe the workpapers for Schedule 20.

A. The supporting workpaper for the A&G Expense schedule is a Spreadsheet with a series of tabs which itemize the exclusion amounts by category type and FERC Account number.

Shareholder and Other tab: The Shareholder and Other tab of the Schedule 20 workpaper spreadsheet supports the shareholder and other exclusions that SCE will be taking from its FERC Form 1 recorded amounts, which is itemized by FERC Account number.

Incentives tab: The Incentives tab of the Schedule 20 workpaper spreadsheet supports the adjusted amount of incentive compensation that SCE will recover broken out by each plan or program.

ShareholderExcDetail tab: The ShareholderExcDetail tab in the Spreadsheet supports SCE's shareholder exclusions by FERC Account and provides descriptions of each exclusion.

Acct 930.2 tab: This tab in the Schedule 20 workpaper spreadsheet contains a table which shows the items of Miscellaneous General Expenses contained in SCE's FERC Form 1 filing (page 335), and shows what expense items are included or excluded as well as the Formula Reference of each. In SCE's proposed Formula Rate, the Acct 930.2 tab from SCE's workpaper is shown on Page 9 of 9 is reproduced here:

FERC Form 1 Pg. 335 Line #	Description	FERC Form 1 Amount	Included	Excluded	Formula References
1	Industry Association Dues	$1,905,284	$1,905,284	$0	Sch. 20, Line 35
2	Nuclear Power Research Expenses			$0	
3	Other Experimental and General Research Expenses	$20,644,228	$0	$20,644,228	Sch. 20, Line 35
4	Pub & Dist Info to Stkhldrs…expn servicing outstanding Securities	$689,470	$689,470	$0	
5	Other Expn >=$5,000 show purpose, receipt, amount. Group if < $5,000				
6	Credit Line Fees / Bank Charges	$3,388,145	$3,388,145	$0	
7	Directors' Fees and Expenses	$3,360,179	$3,360,179	$0	
8	Periodic SEC Reports	$390,422	$390,422	$0	
9	Planning and Development of Communication Systems	$1,736,336	$1,736,336	$0	
10	Provision for Doubtful Accounts - Non-Energy Billings	$1,058,304	$0	$1,058,304	Sch. 20, Line 35
11	Vendor Discounts	-$9,894,818	-$9,894,818	$0	
12	Accounting Suspense	-$1,406,746	$0	-$1,406,746	Sch. 20, Line 35
13	Miscellaneous	-$630,654	-$861,218	$230,564	
14					
15	Sales Tax Refund Audit Period (2008-2011)	-4,965,913	-4,965,913		
15	Payment to CEC / CPUC	$0		$0	Sch. 20, Line 35
16	Administrative and General Expense Charged or Paid to Others	$1,057,936	$1,057,936	$0	Sch. 20, Line 35
17	Balance Sheet Write-Off	$1,539,576	$0	$1,539,576	
46	Total	$18,871,749	-$3,194,177	$22,065,926	

V. FORMAT OF THE SCHEDULE AND WORKPAPERS ASSOCIATED WITH FF&U EXPENSE

Q. Please describe the format of Schedule 28-FF&U of the Formula Rate Spreadsheet.

A. This schedule contains the Franchise Fee and Uncollectibles Factors used in the new formula rate mechanism to calculate Franchise Fees Expense and Uncollectibles Expense. Schedule 28 of Exhibit No. SCE-4 lists the Approved Franchise Fees Factor and the Approved Uncollectibles Expense Factor as determined through SCE's General Rate Case proceedings at the CPUC.

VI. A&G EXPENSE CHANGES IN THE PROPOSED FORMULA RATE COMPARED TO SCE'S ORIGINAL FORMULA RATE

Q. Can you briefly describe the changes in this proposed Formula Rate from the Original Formula Rate used by SCE?

A. The Original Formula Rate has limits placed upon the recovery of employee NOIC, OEIC, and SERP, as well as a complete exclusion of all LTI, Spot Bonus and ACE costs.

In the proposed Formula Rate, SCE will eliminate any caps or limits upon its incentive compensation recovery, so that it will be able to collect all of its incentive compensation costs incurred in a manner that is consistent with FERC policy.

This change ensures that SCE is able to recover the correct amount of NOIC, OEIC, LTI, SERP, ACE, and Spot Bonus expense amounts that are actually incurred for its Administrative and General function employees. Further, in this proposed Formula Rate, SCE plans to make an annual FPA 205 filing to revise the Authorized PBOPs Expense Amount, as further explained in the testimony of Berton J. Hansen (Exhibit No. SCE-3), where the Original

Formula Rate only required a filing under certain conditions based upon the results of a formulaic test that was required to be performed every 2 years.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Robert G. Mindess, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Robert G. Mindess

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Robert Gary Mindess, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
JEE KIM

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-13)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
JEE KIM

(EXHIBIT SCE-13)

Ms. Kim discusses Southern California Edison Company's ("SCE") formulaic dertermination of the Revenue Credits component for the Prior Year Transmission Revenue Requirement ("TRR") and True Up TRR, including the component relating to the Gross Revenue Sharing Mechanism.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	**)))**	**Dkt . No. ER18-______-000**

PREPARED DIRECT TESTIMONY OF
JEE KIM
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Jee Kim, and my business address is 8631 Rush Street, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Project Manager in the FERC Rates & Market Integration Division within Edison's Regulatory Affairs organizational unit. My primary responsibilities include providing analysis and policy guidance supporting the development of pricing and related rate terms associated with contracts and services subject to the jurisdiction of the Federal Energy Regulatory Commission ("FERC" or "Commission").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from the University of California Irvine in September 2003. In February 2008, I joined SCE as a Financial Analyst in the Regulatory Policy and Affairs Department, where my responsibilities included supporting the development of the stated rate case and annual Formula Updates, supporting the development of the annual filing for SCE Construction Work In Progress ("CWIP") Balancing Account, and supporting the development of Wholesale Distribution Access Charges for wholesale load customers.

Q. Have you submitted testimony to the Commission previously?

A. Yes, I sponsored testimony in Docket No. ER18-154.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony supports the calculation of Schedule 21 in the proposed Formula Rate. The purpose of my testimony is to explain: 1) the proposed formulaic determination of the Revenue Credits component of the Prior Year Transmission Revenue Requirements ("TRR") and True Up TRR, including the component relating to the Gross Revenues Sharing Mechanism ("GRSM");
2) the California Public Utilities Commission ("CPUC") approved GRSM and the determination of the ratepayer share of Other Operating Revenue ("OOR") from non-tariffed products and services ("NTP&S") pursuant to the GRSM; and 3) the calculation of Revenue Credits on Schedule 21 of the proposed Formula Rate to be in the Prior Year TRR and True Up TRR.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 21 (Revenue Credits).

Q. Is SCE proposing any changes to Schedule 21 relating to the Original Formula Rate?

A. SCE is proposing no methodological changes to the proposed treatment of OOR or GRSM from the original formula. However, SCE is proposing two formatting changes. The first formatting change is to make Column E or the "Category" column yellow shaded input cells. This revision will allow SCE the flexibility to revise the category of a Revenue Credit item in an Annual Update filing if the item has in fact changed categorization. The second formatting change is removing historical OOR and GRSM line items that have had no activity for the past several years. The following table summarizes the historical line items SCE is proposing to remove from Schedule 21.

Line	FERC ACCT	Ledger ACCT #	ACCT Description	Category
1c	450	4191120	Non-Residential Late Payment	Traditional OOR
7a	453	4183110	Sales of Water & Water Power – San Joaquin	Traditional OOR
7b	453	4183115	Sales of Water & Water Power - Headwater	Traditional OOR
7c	453	-	Miscellaneous Adjustments	Traditional OOR
10d	454	4184116	Joint Pole – Tariffed Process & Eng Fees – Conduit	Traditional OOR
10e	454	4184118	Joint Pole – PI Attchmnt Audit – Undoc P&E Fee	Traditional OOR
12t	456	4186520	RTTC Revenue	GRSM
12x	456	4186536	Other Inc/erd Party DC-ESM	GRSM
12y	456	4186538	3rd Party-Div Tmg-Cr PPD training	GRSM
12oo	456	4188818	FTR Auction Revenue	Other Ratemaking
12qq	456	4196154	Direct Access Monthly Customer Charges	Traditional OOR
12aaa	456	4206515	Operating Miscellaneous Land & Facilities	GRSM
15j	456.1	4198115	High Voltage Trans Access Rev (Existing Contracts)	Other Ratemaking

15q	456.1	4198128	Scheduling/Dispatch Revenues (CSS)	Traditional OOR
24a	417	4863135	ECS – Pass Pole Attachments	GRSM
24g	417	4864110	ECS – Infrastructure Leasing	GRSM
28e	418.1		SCE Capital Company	Traditional OOR

II. REVENUE CREDITS

Q. What are Revenue Credits?

A. Revenue Credits consist of revenues received by SCE from sources other than the sale of electric power. Most of this revenue is recorded in FERC Accounts 450 through 457. Revenue Credits received from non-utility operations or from subsidiaries is recorded in FERC Accounts 417 and 418.1, respectively. Depending on the activity generating the Revenue Credits, such revenue is either returned entirely to ratepayers or shared between ratepayers and shareholders.

Q. Please describe the various FERC Accounts in which Revenue Credits are booked.

A. FERC Account 450, Forfeited Deposits, and FERC Account 451, Miscellaneous Service Revenues, are related to the provision of retail service and include revenues from charges adopted by the CPUC associated with the establishment and maintenance of electric service for SCE's retail customers. FERC Account 453, Sales of Water and Water Power, contains revenues received for sales of power from SCE's hydroelectric projects. FERC Account 454, Rent from Electric Property, contains revenues received from the use by others of land, buildings, and other property. FERC Account 456, Other Electric Revenues, is composed of various items not included in FERC Accounts 450, 451, 453 and 454. FERC Account 456.1, revenues from Transmission of Electricity of

Others, contains revenues received for transmission service to third parties over SCE's transmission facilities which includes Existing Transmission Contract ("ETC") revenues. FERC Account 457.1, Regional Transmission Service Revenues, contains revenues received from scheduling, control, and dispatching services provided by SCE. FERC Account 457.2, Miscellaneous Revenues, contains revenues and reimbursements received for costs incurred by regional transmission service providers not provided for elsewhere. FERC Account 417, Revenues from Nonutility Operations, contains revenues received from activities not related to utility service but that are nonetheless part of SCE. FERC Account 418.1, Equity in Earning of Subsidiary Companies, contains revenues from subsidiary companies.

Q. How are Revenue Credits treated in the proposed Formula Rate?

A. Revenue Credits are calculated in Schedule 21 of the proposed Formula Rate and are an input to both the Prior Year TRR (a component of the Base TRR, which is the projected rate charged to customers, and which is calculated in Schedule 1), and the True Up TRR (SCE's actual costs of service for the Prior Year, which is calculated in Schedule 4). Revenue credits are a reduction to the Prior Year TRR (Schedule 1, Line 72) and to the True Up TRR (Schedule 4, Line 33).

Revenue credits can be categorized into two different types. The first comes from traditional revenue generating activities that have historically been classified as other operating revenue. This type of revenue ("Traditional OOR") is returned 100% to ratepayers as a credit to Prior Year TRR and True Up TRR. The second category is revenue derived from non-tariffed products and services ("NTP&S") activities subject to the CPUC-approved GRSM. GRSM revenue is shared between ratepayers and shareholders according to percentages prescribed under the mechanism. Like Traditional OOR, the ratepayers' share of GRSM revenue is a credit to the Prior Year TRR and True Up TRR.

Q. How are Revenue Credits calculated?

A. As described in detail below, the Revenue Credits schedule (Schedule 21) in the proposed Formula Rate calculates the total Traditional OOR and GRSM Revenue Credit to retail and wholesale ratepayers that take service over the facilities owned by SCE, but under Operational Control of the California Independent System Operator ("ISO"), to be used as a credit against the Prior Year TRR and True Up TRR. I will address both types of Revenue Credits, and explain how each is calculated under the formula rate.

III. TRADITIONAL OOR

Q. How was the Traditional OOR component of Revenue Credits developed in the proposed Formula Rate?

A. First, SCE identified and listed in Schedule 21 all revenue accounts currently generating either Traditional OOR or GRSM revenue. The accounts are listed by account, description and category (any new revenue accounts would be included in the Annual Update filing). Second, the formula calls for the jurisdictional allocation of revenue from Traditional OOR accounts involving ISO facilities between ISO and non-ISO ratepayers (Schedule 21, Columns F-H), based on what accounts involve ISO facilities. Finally, the revenue allocable to ISO ratepayers is included in the Revenue Credit to ISO ratepayers under the formula transmission rate (Schedule 21, Line 44).

Schedule 21 further identifies any Traditional OOR account that is handled via an existing balancing account. Such OOR accounts are labeled as Other Ratemaking Accounts. The formula does not credit ISO ratepayers with any revenue from Other Ratemaking Accounts associated with FERC balancing accounts, as this revenue is flowed back to ISO ratepayers via such balancing accounts. Any revenue from Other Ratemaking Accounts associated with CPUC balancing accounts attributable to ISO facilities is listed under column G, Traditional OOR – ISO, and credited back to ISO ratepayers in the same manner as Traditional OOR. The formula provides for the jurisdictional allocation of these amounts based on either the currently approved CPUC Base Revenue Requirement Balancing Account (BRRBA) allocator (Column N, Note 12), or the CPUC GRC allocator (Column N, Note 7).

Q. Please identify all Traditional OOR accounts that were identified as utilizing ISO facilities and indicate how the revenue allocable to ISO ratepayers were determined.

A. The following table summarizes the Traditional OOR accounts utilizing ISO facilities and how the revenue was allocated to ISO ratepayers.

FERC ACCT	Ledger ACCT #	Activity	Description	Category	Revenue Allocation
454	4184810	Facility Cost - EIX/Nonutility	Revenue received from non-utility operations for labor and use of facilities devoted to utility operations.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
454	4184820	Rent Billed to Non-Utility Affiliates	Rental revenue received from non-utility affiliates.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
454	4194135	Interconnect Facility Finance Charge	Revenue received from customers for use of ISO and non-ISO facilities.	Traditional OOR	Review of facilities providing service.
454	4184821	Rent Billed to Utility Affiliates	Rental revenue received from utility affiliates.	Traditional OOR	Portion of revenue allocated to ISO based on CPUC allocator
454	4184811	Facility Cost-Utility	Revenue received from subsidiaries for labor and use of facilities devoted to utility operations.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
456	4186155	Non-Utility Subs Labor Markup	Markup of labor charges to non-utility subsidiaries.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
456	4196176	Interconnect Facility Finance Charge	Revenue received from customers for use of ISO and non-ISO facilities.	Traditional OOR	Review of facilities providing service.

456	4186156	Non-Utility Subs Labor Markup	Markup of labor charges to non-utility subsidiaries.	Other Ratemaking	Portion of revenue allocated to ISO based on CPUC allocator
456	4186128	Misc ISO Revenue	Revenue from the sale of Four Corners to APS.	Traditional OOR	Direct assignment to ISO
456.1	4198110	Transmission of Elec of Others	Revenue from existing transmission contracts utilizing ISO facilities.	Traditional OOR	Direct assignment to ISO
418.1		Edison Material Supply (EMS)	Subsidiary revenue	Traditional OOR	Portion of revenue allocated to ISO based on CPUC allocator

Q. Are you proposing any changes to the method for allocating the amount of revenue allocable to ISO ratepayers for the items tabulated above?

A. No. The allocations are identical to the Original Formula Rate.

Q. What are the two primary drivers of the Traditional OOR allocated to ISO during 2016?

A. The two primary drivers of the Traditional OOR allocated to ISO are the ETC revenues and the revenue from the sale of Four Corners to Arizona Public Service Electric Company ("APS"). The ETC revenues contributes \$46.7 million out of the \$68.8 million, while the one-time revenues from the sale of Four Corners contributes \$18 million.

Q. On what basis was it determined that the remaining Traditional OOR accounts listed in Schedule 21, not listed in the table above did not contain revenue attributable to ISO ratepayers?

A. The remaining Traditional OOR accounts were determined to not involve ISO facilities for one of the following reasons:

1. The activity involved was related to CPUC jurisdictional services.
2. The activity involved was related to generation.
3. The activity involved was related to Non-ISO facilities.

Column N of Schedule 21 indicates the specific reason for each of the accounts not containing revenue allocable to ISO ratepayers.

IV. NTP&S ACTIVITIES SUBJECT TO GRSM

Q. Please explain NTP&S.

A. Generally speaking, NTP&S are products and services other than traditional electric services that SCE offers to third parties that make secondary or complementary use of temporarily available capacity in utility assets and personnel. This temporarily available capacity may result from varying patterns of utilization, the need to plan for future utility-related growth, or the development of compatible secondary uses of the utility assets. NTP&S are offered at market-based prices that are not regulated by either the CPUC or the FERC. A complete list of SCE's NTP&S categories and a description of each is contained in Exhibit SCE-14. (Attaching CPUC tariff pursuant to CPUC Decision No. 99-09-070) In many cases, the offering of these NTP&S requires significant incremental costs (expense and capital). These incremental costs are not allocated to either retail or wholesale ratepayers; 100% of the incremental costs are borne by SCE's shareholders.

Q. What are the criteria for designating an NTP&S category as Passive or Active?

A. NTP&S categories designated as Passive are typically those in which SCE does not actively participate in the business activity for which the utility assets are being utilized for secondary purposes, or where SCE shareholders contribute little to no capital or resources in the business opportunity. NTP&S categories designated as Active are typically those where SCE takes an active role in the business for which the utility assets are being used for secondary purposes where SCE shareholders contribute new capital or resources in the opportunity.

Q. Please describe how the incremental costs associated with generating NTP&S gross revenues are treated.

A. Under the GRSM, all incremental costs (expense or capital) associated with the offering of NTP&S are the responsibility of, and allocated to, SCE's shareholders, not its ratepayers. Incremental costs are defined as those costs that would not be incurred "but for" the offering of the NTP&S. For example, in the leasing of a right-of-way for a mini-storage facility, the original cost of the land would not be an incremental cost because ratepayers are still getting the full usage of the land for utility purposes and the use of the land for a complementary, secondary use does not increase the ratepayers' costs associated with the land. However, if SCE is required to pay fees to re-zone the land for a mini-storage site, the fees would constitute incremental costs and would be the responsibility of shareholders, not ratepayers. In addition, shareholders are responsible for any liabilities associated with SCE's NTP&S offerings. Ratepayers are responsible for none of the incremental costs or risks associated with NTP&S.

Q. What is the impact to ratepayers if in a given year incremental costs exceed NTP&S gross revenues?

A. There is no impact on ratepayers. If SCE's incremental costs are greater than its NTP&S gross revenues, ratepayers still receive their same share of gross revenues under the GRSM. Under the GRSM, ratepayers are not impacted by the level of incremental costs or risks incurred by SCE in the offering of NTP&S.

Q. Please explain GRSM.

A. The GRSM is a mechanism adopted by the CPUC[1] for the sharing between ratepayers and shareholders, on a gross revenue basis, of certain OOR revenues

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1 GRSM adopted by the CPUC in Decision 99-09-070 issued on September 16, 1999.

that SCE receives from NTP&S activities. Under this mechanism, all incremental costs associated with NTP&S are allocated to shareholders. The CPUC-adopted GRSM also establishes a threshold gross revenue credit to ratepayers ("GRSM Threshold") of $16.671 million from NTP&S. Since the entire amount of the GRSM Threshold is a credit to SCE's customer rates, it guarantees ratepayer benefit from the mechanism.

The CPUC-jurisdictional share of the GRSM Threshold is reflected as a revenue credit on a forecast basis in SCE's revenue requirement in its CPUC general rate cases. Pursuant to the proposed FERC Formula, a share of the GRSM Threshold is flowed thru to ratepayers as Revenue Credit on Schedule 21.

Incremental gross revenues in excess of the GRSM Threshold ("Incremental Gross Revenues") are subject to sharing between SCE's shareholders and ratepayers based on a CPUC-prescribed methodology under the GRSM. Each of the NTP&S categories identified under GRSM is designated as either "Active" or "Passive." On an annual basis, once the pre-established GRSM Threshold has been met, ratepayers receive 10 percent of the Incremental Gross Revenues for Active categories (Schedule 21, Line 38) and 30 percent for Passive categories (Schedule 21, Line 40). The CPUC-jurisdictional portion of the ratepayers' share of the Incremental Gross Revenues is flowed through to ratepayers on a recorded basis through operation of a balancing account mechanism. The proposed FERC Formula flows a share of the Incremental Gross Revenues through Schedule 21.

Q. Does the GRSM address the sharing between ISO and non-ISO ratepayers?

A. No. The CPUC adopted GRSM does not address the jurisdictional allocation of the ratepayers' share of NTP&S revenue.

Q. How does the proposed Formula Rate allocate the ratepayers' share of GRSM revenue between ISO and non-ISO ratepayers?

A. The proposed Formula Rate utilizes the historical jurisdictional allocation of the GRSM Threshold, and applies this same FERC allocation percentage to Incremental Gross Revenues (Schedule 21, Line 41).

Q. Why was the GRSM Threshold established?

A. The $16.671 million GRSM Threshold represents the historical base amount of gross revenues associated with NTP&S that were reflected on a forecast basis in SCE's retail rates at the time the GRSM was adopted. Since ratepayers were already receiving 100% of these revenues as a revenue credit, the GRSM Threshold was established to ensure that ratepayers continued to receive, at a minimum, this level of historical revenues. However, any incremental costs associated with these revenues are now paid 100% by shareholders. In order to ensure that ratepayers continue to receive the GRSM Threshold, it is flowed through 100% to ratepayers as a revenue credit in SCE's rate cases and is not shared with shareholders. These revenues are credited to ratepayers' rates regardless of the level of actual NTP&S gross revenues.

Q. Please explain the jurisdictional allocation of the GRSM Threshold.

A. The current jurisdictional allocation approved by the CPUC assigns $5,425,127 as a revenue credit to ISO ratepayers, and this is reflected in Schedule 21, Line 34. The jurisdictional split of the GRSM Threshold results in approximately 32.5% being allocated to ISO ratepayers (Schedule 21, Line 41).

Q. Why is it reasonable to apply the historical jurisdictional allocation of the GRSM Threshold to Incremental Gross Revenues?

A. The proposed Formula Rate allocates Incremental Gross Revenues to FERC-jurisdictional transmission ratepayers in the same proportion that the GRSM

Threshold is allocated (32.54 %). Such allocation rate is reasonable since the Incremental Gross Revenues are derived from many of the same services that generate the GRSM Threshold, which rely on assets common to the transmission and distribution functions. Under the GRSM, an individual service is not classified as either part of the GRSM Threshold or Incremental Gross Revenues. In addition, as described above, the jurisdictional allocation of the Threshold Amount was based on a functionalization that reviewed individual functions that utilize different utility assets - some transmission, some distribution, some generation and some a combination. In this sense, the functions that generate the GRSM Threshold share the same characteristics as the functions that generate the Incremental Gross Revenues.

Q. Why should SCE shareholders receive any of the Incremental Gross Revenues?

A. The GRSM was designed to create a fair and equitable mechanism that incentivized SCE to expand its NTP&S to generate revenues for both ratepayers and shareholders. In addition, the GRSM was designed to provide sufficient long-term certainty regarding the treatment of NTP&S revenues and incremental costs so that SCE could evaluate whether or not to invest shareholder capital into NTP&S. Since shareholders are responsible for all incremental costs (expense and capital), they need to receive a portion of the Incremental Gross Revenues to cover these incremental costs and any incremental taxes incurred as well as to provide an incentive to take risks and pursue NTP&S opportunities. In addition, shareholders assume all of the risks and liabilities associated with NTP&S. The gross revenues from NTP&S were generated as a result of considerable work, sound decision-making, proper incentives and the expenditure of shareholder funded incremental costs. The ratepayers receive their share of Incremental Gross Revenues despite paying none of the incremental costs, taking none of the risk and having no responsibility for any of the liabilities associated with NTP&S.

Q. Please summarize how the GRSM has operated since its inception in 1999.

A. As shown in Table 1, since the inception of the GRSM through 2016, SCE has generated approximately $1,507.0 million in total gross revenues from NTP&S. Under the GRSM, ratepayers have received revenue credits of $488.2 million, $283.9 million through the annual GRSM Threshold and an additional $204.3 million as their share of the Incremental Gross Revenues. While shareholders have received $1,018.8 million of the Incremental Gross Revenues, they have also incurred $710.4 million in incremental costs and an estimated $124.6 million in incremental taxes associated with NTP&S. On a net basis, shareholders have received $183.8 million compared to ratepayers who have received $488.2 million. Thus, over the life of the GRSM, ratepayers have received 73% of the net revenues compared to shareholders 27%.

Table 1

Southern California Edison Company

Gross Revenue Sharing Mechanism

Summary of Operations

($ Millions)

Line		1999*	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
1	Total Gross Revenue	16.0	66.1	78.0	74.4	88.8	76.4	83.6	93.8	108.4	100.6	95.7	91.3	98.6	93.9	92.1	82.9	84.7	81.7	1,507.0
2	GRSM Threshold	N/A	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	283.9
3	Total ratepayers' Share of Incremental Gross Revenues	2.7	8.0	9.8	9.9	11.2	10.6	11.7	12.7	16.6	13.6	13.0	12.5	13.5	12.8	12.0	11.1	11.4	11.2	204.3
4	Total ratepayers' Net Benefits (Line 2 + Line 3)	2.7	24.7	26.5	26.6	27.9	27.3	28.4	29.4	33.3	30.3	29.7	29.2	30.2	29.5	28.7	27.8	28.1	27.9	488.2
5	Shareholders' Share of Incremental Gross Revenues (Line 1 - Line 4)	13.3	41.4	51.5	47.8	60.9	49.1	55.2	64.4	75.1	70.3	66.0	62.1	68.4	64.4	63.4	55.1	56.6	53.8	1,018.8
6	Total Incremental Costs (Allocated to Shareholders)	13.2	42.1	46.4	38.9	33.3	36.6	38.3	49.1	58.7	49.5	43.6	42.4	45.7	42.0	39.8	29.4	27.8	33.8	710.4
7	Pre-Tax Shareholders' Net Revenues (Line 5 - Line 6)	0.1	-0.7	5.1	8.9	27.6	12.5	16.9	15.3	16.4	20.8	22.4	19.7	22.7	22.4	23.7	25.7	28.8	20.0	308.4
8	Taxes (Line 7 * Tax Rate)**	0.0	-0.3	2.1	3.6	11.1	5.0	6.8	6.2	6.6	8.3	9.1	8.0	9.2	9.1	9.6	10.4	11.7	8.1	124.6
9	Total Shareholders' Net Revenues (Line 7 - Line 8)	0.1	-0.4	3.0	5.3	16.5	7.5	10.1	9.1	9.8	12.5	13.3	11.7	13.5	13.3	14.1	15.3	17.1	11.9	183.8
10	**Ratepayer' Share of Net Revenues (Line 4) / (Line 4 + Line 9)**	**96%**	**100%**	**90%**	**83%**	**63%**	**78%**	**74%**	**76%**	**77%**	**71%**	**69%**	**71%**	**69%**	**69%**	**67%**	**65%**	**62%**	**70%**	**73%**
11	**Shareholders' Share of Net Revenues** (100% - Line 10)	**4%**	**N/A**	**10%**	**17%**	**37%**	**22%**	**26%**	**24%**	**23%**	**29%**	**31%**	**29%**	**31%**	**31%**	**33%**	**35%**	**38%**	**30%**	**27%**

* Reflects partial year since GRSM effective 9/16/99

** The following tax rates were used 1999-2002: 40.551%; 2003- 2005: 40.370%; 20067-2008: 40.146%; 2009-2016: 40.588%

Q. Why should SCE's GRSM be adopted as part of the proposed Formula Rate?

A. As demonstrated above, under SCE's GRSM, ratepayers have received 73% of the net revenues from SCE's NTP&S. Ratepayers have received these revenues without incurring any of the incremental costs or risks associated with the NTP&S. In addition, the historical performance of the GRSM has demonstrated that it provides sufficient incentives to SCE to incur both the incremental expenses and capital that are required to offer the NTP&S.

Q. How is the GRSM component of Revenue Credits developed in the proposed Formula Rate?

A. First, SCE has identified and listed in Schedule 21 all NTP&S accounts and designated them as either Active or Passive pursuant to the GRSM (any new NTP&S accounts would be included in the Annual Update filing). Second, SCE has identified the gross revenues received as either GRSM Threshold (Column K, labeled "Threshold") or Incremental Gross Revenues (Column L, labeled "Incremental"). The first $16.671 million in gross revenue that is received in a given year is automatically recorded as GRSM Threshold. All additional gross revenues above the threshold amount are recorded as Incremental Gross Revenues. Third, SCE has determined the ratepayers' share of Incremental Gross Revenues according to the Active/Passive sharing percentages prescribed by the GRSM (Schedule 21, Lines 36 thru 42). Ratepayers receive 10% of Active Incremental Gross Revenues, and 30% of Passive Incremental Gross Revenues. Fourth, ISO ratepayers are allocated 32.5% of the GRSM Threshold. ISO ratepayers are also allocated 32.5% of the ratepayers' share of Incremental Gross Revenues. Finally, the GRSM revenue allocated to ISO ratepayers is included in the Revenue Credit to ISO ratepayers under this formula transmission rate (Schedule 21, Line 44).

Q. Does SCE's proposed Formula Rate Protocols address the GRSM mechanism?

A. Yes, the GRSM is called out in the proposed Formula Rate Protocols as single-issue Section 205 filing. The Protocols provide that if the CPUC adopts revisions to the GRSM, SCE will make a filing with the Commission to make conforming change to Schedule 21. It is necessary for the GRSM to be consistent in both the CPUC and FERC jurisdictions to assure fair treatment to both SCE's ratepayers and shareholders. Inconsistent treatment of the NTP&S revenues in the two jurisdictions could result in unnecessary litigation over allocation of such revenue, or dissuade SCE ratepayers from continuing to pursue NTP&S.

Q. Are you supporting the development of any workpapers in the proposed Formula Rate?

A. Yes, I am supporting the development of the One Time Adjustment to Prior Period True Up TRR workpaper to Schedule 3. In the proposed Formula Rate the One Time Adjustment to Prior Period True Up TRR is -$77,804, as shown on Schedule 3, Line 12, Column 4.

V. CONCLUSION

Q. What are SCE's total Revenue Credit Amounts for 2016 attributable to this Formula Rate filing?

A. SCE's total Revenue Credits is $77,928,965 as shown on Schedule 21, Line 44.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Jee Kim, being first duly sworn, on oath says that she is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers would, under oath, be the same.

Jee Kim

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Jee Y. Kim, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

<u>EXHIBIT SCE-14</u>

EXHIBIT TO THE TESTIMONY OF MS. JEE KIM

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Southern California Edison — Original — Cal. PUC Sheet No. 26584-E
Rosemead, California — Cancelling — Cal. PUC Sheet No.

PRELIMINARY STATEMENT — Sheet 1

G. Gross Revenue Sharing Mechanism

The purpose of the Gross Revenue Sharing Mechanism (GRSM) is to record the customers' share of certain Other Operating Revenue (OOR) pursuant to Decision No. 99-09-070 (D.99-09-070).

In D.99-09-070 the Commission adopted, with clarifications, a Settlement Agreement between SCE and the Office of Ratepayer Advocates (ORA) for a gross revenue sharing mechanism associated with the SCE's non-tariffed products and services.

The gross revenue sharing mechanism adopted in D.99-09-070 applies to all of SCE's OOR, except revenue that is:

- Derived from tariffs, fees, or charges established by the Commission or Federal Energy Regulatory Commission;
- Subject to other established ratemaking procedures or mechanisms; or
- Subject to the Demand Side Management Balancing Account.

1. Definitions

   a. Active Sharing Allocation

      The Active Sharing Allocation is 90%/10% (shareholder/customer) for Incremental OOR associated with non-tariffed products and services deemed "active" by the Commission. The allocation shall apply over the life of the non-tariffed product or service offering and/or applicable contract.

   b. Incremental OOR

      Incremental OOR is the recorded gross revenue derived from non-tariffed products and services subject to the GRSM that exceeds the OOR Threshold during each calendar year. Incremental OOR is subject to the gross revenue sharing mechanism adopted in D.99-09-070, and shall be allocated between shareholders and customers using the Active Sharing Allocation or the Passive Sharing Allocation.

(Continued)

PRELIMINARY STATEMENT Sheet 2

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

1. Definitions (Continued)

c. OOR Threshold

The annual calendar year OOR Threshold is equivalent to the amount of OOR from non-tariffed products and services reflected as a revenue credit in SCE's most recent General Rate Case (GRC). The current OOR Threshold is $16,671,389 and is based upon the level of OOR from non-tariffed products and services reflected as a revenue credit in SCE's 1995 Test Year GRC (D.96-01-011). This amount shall remain fixed until SCE's next GRC or otherwise modified by the Commission. Recorded non-tariffed products and services gross revenues that is greater than the OOR Threshold during any calendar year is considered Incremental OOR and shall be allocated to SCE's shareholders and customers using the Active Sharing Allocation or the Passive Sharing Allocation.

d. Passive Sharing Allocation

The Passive Sharing Allocation is 70%/30% (shareholder/customer) for Incremental OOR associated with non-tariffed products and services deemed "passive" by the Commission. The allocation shall apply over the life of the non-tariffed product or service offering and/or applicable contract.

2. Operation of the Gross Revenue Sharing Tracking Account

SCE shall maintain a Gross Revenue Sharing Tracking Account (GRSTA). Entries to the GRSTA shall be made on a monthly basis and shall be determined as follows:

a. GRSTA entries when the annual calendar year OOR Threshold is not reached.

The following calculation shall commence on January 1st of each calendar year, and shall continue until the OOR Threshold is reached during the calendar year.

(1) Annual calendar year OOR Threshold;

(2) Less: Recorded calendar year-to-date gross revenues from non-tariffed products and services subject to the GRSM (as of the end of the applicable month);

(3) If the result of "2.a.(1)" and "2.a.(2)" above is a positive amount, there shall be no entries made to the GRSTA for the month.

(Continued)

PRELIMINARY STATEMENT Sheet 3

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

2. Operation of the GRSTA (Continued)

a. GRSTA entries when the annual calendar year OOR Threshold is not reached. (Continued)

(4) If the result of the calculation of “2.a.(1)” and “2.a.(2)” above is a negative amount, then the OOR Threshold has been reached and recorded Incremental OOR must be allocated between shareholders and customers. See 2.b. and 2.c. below.

b. GRSTA entries in the month that the OOR Threshold is reached.

(1) If the result of the calculation of “2.a.(1)” and “2.a.(2)” above is a negative amount, then the Incremental OOR for that month shall be shared between shareholders and customers using the Active Sharing Allocation and the Passive Sharing Allocation.

(2) In the month of each calendar year that the OOR Threshold has been reached, Incremental OOR shall be allocated between “active” and “passive” non-tariffed products and services based upon the proportion for each of the non-tariffed products and services gross revenues recorded during the month.

(3) The customers’ share of Incremental OOR shall be credited to the GRSTA by applying the Active Sharing Allocation and the Passive Sharing Allocation. The shareholder portion of Incremental OOR shall not be recorded in the GRSTA.

c. GRSTA entries in the months during the calendar year subsequent to the month in which the OOR Threshold is reached.

During these months of each calendar year all recorded non-tariffed products and services OOR subject to the GRSM shall be considered Incremental OOR for gross revenue sharing purposes.

(1) Recorded Incremental OOR for the month shall be allocated to shareholders and customers by applying the applicable Active Sharing Allocation or Passive Sharing Allocation to the recorded gross revenues from non-tariffed products and services subject to the GRSM.

(2) The customers’ share of the resultant allocations shall be credited to the GRSTA. The shareholder portion of Incremental OOR shall not be recorded in the GRSTA.

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

2. Operation of the GRSTA (Continued)

d. Monthly Interest

Interest shall accrue monthly in the GRSTA by applying the Interest Rate to the average of the beginning of month balance and the end of month balance.

e. Annual Calendar Year-End Transfers of the GRSTA

At the end of each calendar year SCE shall transfer the balance in the GRSTA (including accrued interest) to the Electric Deferred Refund Account (EDRA), or other ratemaking mechanism authorized by the Commission. On each January 1st the balance in the GRSTA shall be reset to zero subsequent to the transfer of the December 31st GRSTA balance.

3. Advice Letter Process

SCE may request a change in classification from “passive” to “active” for an existing non-tariffed product and service offering, as defined in Section F of the OOR Settlement Agreement (as authorized in D.99-09-070), by filing an advice letter with the Commission.

To reclassify a product or service offering as “active,” the advice letter must show that the product or service offering involves incremental shareholder investment of at least $225,000 (either on a one-time basis or within a twelve-month period).

SCE shall not file more than four such advice letters in any calendar year. Prior to filing any such advice letter, SCE shall meet with the ORA, or its successor organization, to discuss the planned advice letter and the proposed classification of the new product or service offering.

Advice letters requesting a reclassification of a product or service offering from “passive” to “active” shall be governed by General Order 96-A, or its successor.

PRELIMINARY STATEMENT — Sheet 5

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Secondary Use of Transmission Right-of-Ways and Land	- Placement of third-party communications equipment, attachments, conduit and cable	Passive	
	- Agricultural/Horticultural		
	- Storage facilities		
	- Parking lots		
	- Vehicle storage		
	- Film production site locations		
	- Sale or trading of excess water rights		
	- Sale or trading of mineral rights		
	- Billboard Placements		(N)
	- Parks and Recreation		|
	- Stables		(N)
Secondary Use of Distribution Right-of-Ways, Land, Facilities and Substations	- Placement of third-party communications equipment, attachments, conduit and cable	Passive	
	- Agricultural/Horticultural		
	- Parking lots		
	- Vehicle storage		
	- Film production site locations		
	- Sale or trading of excess water rights		
	- Sale or trading of mineral rights		
	- Billboard Placements		(N)
	- Parks and Recreation		|
	- Stables		|
	- Storage Facilities		(N)
Secondary Use of SCE-Owned Generation Facilities and Land	- Placement of third-party communications equipment, attachments, conduit and cable	Passive	
	- Agricultural/Horticultural		
	- Film production site locations		
	- Sale or trading of excess water rights		
	- Sale or trading of mineral rights		
	- Billboard Placements		(N)
	- Parks and Recreation		|
	- Stables		|
	- Vehicle Storage		|
	- Parking Lots		(N)

(Continued)

PRELIMINARY STATEMENT Sheet 6

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Secondary Use of Utility Owned Buildings and Offices	- Meetings/Conferences - Office space - Placement of third party communications equipment, attachments, conduit and cable - Cafeteria and Vending Machines	Passive	(T) (T) (N)
Use of Transmission Towers, Distribution Poles, Facilities, Conduits, Ducts and Streetlight Poles	- Placement of third-party communications equipment, attachments, conduit and cable	Passive	
Use of Communications and Computing Systems	- Circuits, wave lengths and radio spectrum - Dark fiber on fiber optic system - Cable pairs on copper communication cables - Communications and computing capacity, installation, maintenance and support - Fiber optic and other communications cable construction, equipment installation, and site development - Marketing of third parties' right-of-ways, poles, towers and other facilities for communication-related purposes - Infrastructure-related telecommunication services - Infrastructure-related computing services - Communication and computing service center services	Active	(N) | | | (N)

(Continued)

PRELIMINARY STATEMENT Sheet 7

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
License of Utility Software	- Utility developed software (e.g., Outage Management System, Fleet Management System) - Software licensed to Utility (e.g., energy usage tracking software)	Passive	
Licensing of Utility-Held Patents[1/]	- Licensing of Utility developed technologies such as the Insulator Washing Technology	Passive	(T)
Property Management, Property Maintenance and Real Property Brokerage Services	- Title searches - Brokerage activities - Property management - Janitorial and building maintenance	Passive	
Recreation, Fish and Wildlife Activities	- Campground rentals - Campground maintenance - Fish hatchery	Passive	
Sales of Timber Stands on Utility-Owned Property	- Timber sales	Passive	
Use of Customer Technology Application Center (CTAC) and Agricultural Technology Application Center (AgTAC) Facilities	- Conference facilities - Audiovisual services - Catering - Teleconferencing/downlinks - Technical seminars and training - Partnership training (e.g., with federal government) - Customer product/technology testing and demonstrations - Display space and display set-up - Display development and consulting	Passive	
Electric Vehicle (EV), Battery, and Charger-Related Services	- EV operational, performance, calibration and reliability testing - Battery performance, safety, power quality and reliability testing - Charger operational, performance, reliability, safety, power quality, efficiency and life cycle testing - Customer education and training on EV technologies, operations, charging safety, diagnosis and maintenance	Active	

1/ Does not include revenue sharing mechanism related to financial benefits of Intellectual Property that was developed under Electric Program Investment Charge (EPIC) funds in D.13-11-025. (N)
(N)

(Continued)

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Energy Efficiency Engineering Consulting and Technical Services	- Lighting surveys - Lighting systems bid specifications - Lighting systems construction observation - Building energy simulations - End-use consulting - Facilities engineering, analysis and commissioning - Submetering	Passive	

Billing and Customer Communication Center Services for Non-ESPs	- Bill Customization
	- Usage Calculation
	- Bill calculation
	- Bill presentation (e.g., mailing, summary billing, EDI billing, flexible bill routing)
	- Payment processing (e.g., mail, in-person through APA network etc.)
	- Credit and collections activities
	- Customer Communications Center Services for clients' customer calls. These services can be provided in seven languages and include, but are not limited to:
	  - requests for service connection (turn ons)
	  - transfer of service or turn offs
	  - customer credit inquiries
	  - customer extension/payment arrangements
	  - billing inquiries
	  - billing investigations
	  - outage reports
	  - account transfers
		Active	(D)

(Continued)

PRELIMINARY STATEMENT — Sheet 9

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Meter Reading and Field Services for Non-ESPs	- Meter reading (usage measurement) - Transfer of meter reading information - Special and mid-cycle meter reads - Physical and remote turn ons; turn offs - Physical and remote disconnects and reconnects - Meter change-outs - Other field services	Active	
Bill Payment Options	- Pay-by-phone - Pay-by-Internet - Direct Payment - Acceptance of payments for telecommunications providers in rural locations	Passive	(D)
Vehicle Maintenance and Repair	- Vehicle maintenance and repair - Comprehensive Fleet management	Passive	
Transportation and Disposal of Hazardous Materials	- Transportation and disposal of hazardous material such as waste by-product from generation	Active	
Use of Heavy Equipment and Machinery	- Use of heavy equipment such as cranes and rigging services, helicopters and other machinery or equipment	Passive	

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Operation and Maintenance, and Repair of Generation, Transmission and Distribution Related Facilities and Equipment	- Operation of power generation, transmission, and distribution equipment and facilities	Active	(L) (T)(N)(D) (N)
	- On-site Inspection, maintenance, troubleshooting, repair, replacement, and installation of distribution and transmission facilities (e.g., electrical apparatus, streetlights, conductors, towers, poles, transformers)		(T)(C) (C)
	- On-site inspection, maintenance, troubleshooting, and repair of protection systems, telecommunication cables and equipment (e.g., fiber optics and microwave		(N) (D) (N)
	- Metering, measurement and test equipment services (e.g., engineering, system analysis, meter installation, maintenance, testing, calibration, and repair)		(N) (D) (N)
	- Electrical and mechanical engineering and consulting services		(C) (C)
	- Precision dimensional measurement consulting and engineering		(N)(D) (N)
	- Nuclear decommissioning consulting and engineering		(N)(D) (N)
Advanced Testing of Hydraulic Pumps	- Advanced testing of hydraulic pump and associated electrical equipment	Passive	(L) (L)

PRELIMINARY STATEMENT Sheet 11

(Continued)

G. Gross Revenue Sharing Mechanism (Continued)

4. Approved Non-Tariffed Products and Services (Continued)

Product or Service Category	Description of Existing Products and Services	Active/Passive Designation	
Equipment and Machinery Repair, Testing, Maintenance and Calibration	- Shop service repairs of mechanical and electrical apparatus and equipment such as valves, motors, turbines, transformers, and generators - Material testing - Instrumentation repair and calibration - Metering, measurement and test equipment services (e.g., engineering, system analysis, meter installation, maintenance, testing, calibration, and repair) - Electrical and mechanical engineering and consulting and engineering - Training - Precision dimensional measurement consulting and engineering - Nuclear decommissioning consulting and engineering	Active	(L) (T) (T) (N) (D) | | | (N)
Geographic Information Systems (GIS) Services	- Mapping services - Map creation - Specialized geographic data base analysis and development - User training	Passive	(D)
Tariff Sheet Sales	- Tariff sheet sales	Passive	(D) (N)
Recycling Services	- Paper Recycling - Trash Recycling	Passive	|
Training and Technical Certification Services	- Training, technical certification, conferences, and seminars	Passive	| (N)
Material Procurement and Purchasing Services	- Aggregated procurement and purchasing services of machinery, materials, equipment, tools, parts, office equipment, and supplies	Passive	(L) |
Fuel Oil Pipeline System and Storage Facilities	- Fuel oil transportation services - Fuel oil storage services	Not subject to proposed revenue sharing mechanism	| (L)

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
ANTONIO OCEGUEDA

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-15)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
ANTONIO OCEGUEDA

(EXHIBIT SCE-15)

Mr. Ocegueda provides an overview of Plant Held for Future Use under Schedule 11, Abandoned Plant under Schedule 12, Network Upgrade Credits under Schedule 22, Regulatory Assets/Liabilities under Schedule 23, and the Transmission Wages and Salary Allocation Factor and the Transmission Plant Allocation Factor calculated under Schedule 27.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER18-______-000**

PREPARED DIRECT TESTIMONY OF
ANTONIO OCEGUEDA
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Antonio Ocegueda, and my business address is 8631 Rush St, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am a Project Manager in the FERC Rates and Market Integration Division of the Regulatory Affairs Department. My primary responsibilities include developing rates for services that are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Science degree in Mechanical Engineering from Loyola Marymount University in May 1999. I received a Master of Planning degree from the University of Southern California in May 2003. In December 2003, I joined SCE as a Contract Manager in the Regulatory Policy and Contracts Division within the Transmission and Distribution Department, where my responsibilities included management of FERC-jurisdictional transmission and distribution agreements. In January 2006, I transferred to my current position in what was then the Regulatory Operations Department.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in SCE's prior updates to the Transmission Access Charge Balancing Account Adjustment under Docket Nos. ER17-1345, ER16-1272 and ER15-1399. I also submitted testimony in SCE's update to its Reliability Services Balancing Account under Docket Nos. ER17-232 and ER15-216. Finally, I submitted testimony in two of SCE's transmission rate case proceedings (Docket Nos. ER08-1343 and ER11-3697).

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Plant Held for Future Use under Schedule 11, Abandoned Plant under Schedule 12, Network Upgrade Credits under Schedule 22, Regulatory Assets/Liabilities under Schedule 23, and the Transmission Wages and salary Allocation Factor and the Transmission Plant Allocation Factor calculated under Schedule 27 of SCE's proposed Formula Rate.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedules 11 (Plant Held for Future Use), 12 (Abandoned Plant), 22 (Network Upgrade Credits), 23 (Regulatory Assets), and a portion of Schedule 27 relating to the Wages and Salaries Allocation Factor and Plant Allocation Factor (Lines 1-22).

II. TRANSMISSION PLANT HELD FOR FUTURE USE

Q. Please describe how Transmission Plant Held for Future Use is handled under Schedule 11 of the proposed Formula Rate.

A. Transmission Plant Held for Future Use ("PHFU") is typically comprised of two categories of costs. First, it includes land or land rights purchased in advance of transmission plant construction that is intended to be placed under the Operational

Control of the California Independent System Operator Corporation ("CAISO" or "ISO"). Second, PHFU includes any General Plant Held for Future Use. This category of costs is allocated to the ISO based on a labor allocator that I explain in more detail below. Schedule 11 of the proposed Formula Rate reports all categories of PHFU included in ISO rate base. Additionally, Schedule 11 reports any gains or losses related to the sale of land that is part of PHFU. This is consistent with Commission policy that requires gains or losses on the land component of Transmission Plant Held for Future Use to be flowed back to ratepayers. However, gains or losses on non-land Transmission Plant Held for Future Use are not required to be flowed back to ratepayers.

Q. Are there any changes to the treatment of PHFU under the proposed Formula Rate relative to the currently effective Formula Rate for SCE ("Original Formula Rate")?

A. No.

Q. What amount of PHFU is reflected in the proposed Formula Rate 2016 Prior Year TRR, and included in the proposed 2018 Base TRR?

A. For the proposed Formula Rate 2018 Base TRR, the PHFU amount included in the Prior Year TRR for 2016 is $9,942,155 (See Exhibit No. SCE-4, Schedule 11, Line 2a). This amount is related to land purchased for SCE's proposed Alberhill System Project. There is no General Plant Held for Future Use in 2016 reflected in PHFU.

III. ABANDONED PLANT

Q. Please describe how Abandoned Plant is handled in the Proposed Formula Rate.

A. As discussed by Mr. Hansen (Exhibit SCE-3), Abandoned Plant Amortization Expense is included in Schedule 12 of Exhibit No. SCE-4 with respect to projects for which SCE has received a Commission Order approving recovery of prudently incurred costs for projects that are abandoned due to factors beyond SCE's control. Costs are recovered through the approved annual amortization of the abandoned plant costs. Unamortized Abandoned Plant costs may also be included in Rate Base through the Abandoned Plant component of Rate Base. The authorized recovery of abandoned plant for each particular project serves as the inputs to Schedule 12.

Q. Are there any changes to the treatment of Abandoned Plant under the proposed Formula Rate relative to the Original Formula Rate?

A. No.

Q. Please describe the Abandoned Plant inputs under Schedule 12.

A. For each project that has been granted Abandoned Plant treatment by the Commission, Schedule 12 outlines the Abandoned Plant Amortization Expense. This value is consistent with any amount of Abandoned Plant that the Commission has authorized SCE to expense in the Prior Year. Lines 7-17 summarize the Commission approved Abandoned Plant Amortization Expense schedule for a particular project. Schedule 12 also reports the beginning and end of year Abandoned Plant balances (Lines 2 and 3), which serve to compute the Abandoned Plant component of Rate Base.

Q. What is the authorized Abandoned Plant for the 2016 Prior Year reflected in the proposed Formula Rate and included in the proposed 2018 Base TRR?

A. For the proposed Formula Rate Base TRR for 2018, Schedule 12 reflects the Commission approved recovery of $37,069,049 of Abandoned Plant related to the Coolwater-Lugo Transmission Project ("CWLTP"). The recovery of this amount was approved in Docket No. ER16-1025, including the amortization of the amount over the single calendar year of 2016.

The recovery of the Commission approved Abandoned Plant amount relating to the CWLTP is shown in Exhibit No. SCE-4 on Schedule 12, Line 8.

SCE is additionally recovering a Rate Base component of $18,534,525 in the True Up TRR for 2016 based on an average of the Beginning of Year ("BOY") and End of Year ("EOY) balances, as shown in Exhibit No. SCE-4, Schedule 12, Line 4 (and included in the True Up TRR on Schedule 4, Line 4).

IV. NETWORK UPGRADE CREDITS

Q. Please describe Network Upgrade Credits payable to generators.

A. Over the last several years, SCE has entered into numerous agreements for interconnecting new generation projects. Pursuant to these agreements, SCE has collected up-front payments from generators to fund the construction of upgrades to ISO transmission facilities owned by SCE ("Network Upgrades"). Such up-front payments are generally made up of a payment towards work that will be capitalized ("Facility Payment"), and in some cases, a payment towards non-capitalized work ("One-Time Payment"). Under current FERC policy, the up-front payments made by a generator associated with Network Upgrades are subject to refund to the generator with interest. The Network Upgrade Credit is the balance of the monies collected from generators less amount refunded. The Network Upgrade Credit is a reduction to rate base.

Q. Are there any changes to the treatment of Network Upgrade Credits under the proposed Formula Rate relative to the Original Formula Rate?

A. No.

Q. Please describe how Network Upgrade Credits are paid.

A. Network Upgrades are initially financed by the interconnecting generator via upfront payments to SCE. Generally, Network Upgrade Credits are then paid to the interconnection generator over a five-year period, in quarterly installments, beginning on the in-service date of the Network Upgrades.

Q. Please describe how the interest paid to the generators for Network Upgrades is calculated.

A. Interest accrues beginning on the date SCE receives the upfront payments from the interconnecting generator. Such interest is broken down into two periods: (i) the period prior to the in-service date ("Pre-In-Service Interest"); and (ii) the period after the in-service date ("Post-In-Service Interest"). This interest is calculated in accordance with the Commission's regulations, 18 CFR § 35.19a(a).

Q. Please describe the adjustment to the Base TRR for Network Upgrade Credits.

A. To assure recovery of the Network Upgrade Credits and the associated interest expense, SCE makes two adjustments to the calculation of its Base TRR and True Up TRR. First, SCE reduces its ISO rate base with the un-refunded balance of the up-front Facility Payments associated with the Network Upgrades that are included in rate base. This rate base reduction is shown on Schedule 1, Line 17 and Schedule 4, Line 15. The rate base reduction is calculated in Schedule 22. The second adjustment is the addition of an expense item reflecting the interest expense associated with Network Upgrade Credits that SCE paid to generators during the Prior Year. SCE treats these Network Upgrades associated with generator interconnections as any other Network Upgrade. Consequently, SCE reflects the cost of the Network Upgrade in rate base, and accrues Allowance for Funds Used During Construction on the Network Upgrades during construction (with the exception of projects that have been granted Construction Work in Progress recovery). In determining the interest expense to reflect in the Base TRR and True Up TRR, with one exception described below, SCE has excluded any interest costs accrued during construction associated with payments made by the generator (i.e. the Pre-In-Service Interest).

Q. Please describe the "one exception" you refer to above.

A. For One-Time Payments, both the Pre-In-Service and Post-In-Service Interest are included in the transmission cost of service. While Network Upgrade payments are included in rate base, One-Time Costs are not. In order for SCE to be left whole, the Pre-In-Service Interest for One-Time Payments must be, and has been, included in the transmission cost of service. This interest expense is shown on Schedule 1, Line 68 and Schedule 4, Line 29, and is calculated in Schedule 22.

Q. Please summarize the results of your proposal.

A. The rate base adjustment flows through to the ISO ratepayers the benefit associated with the up-front payments used to finance the construction of these Network Upgrades. The second adjustment flows through the costs associated with this source of financing to ISO ratepayers. These two adjustments work together to insure that ISO ratepayers receive the benefit of generator up-front payments, while remaining ultimately responsible for the costs of such Network Upgrades. This is the same approach as SCE has used in its Original Formula Rate.

Q. What amount of Network Upgrade Credits is included in the 2017 Prior Year TRR for the proposed 2018 Base TRR?

A. SCE is including credit to Rate Base of $119,779,556 in the 2016 Prior Year TRR, as shown in Exhibit No. SCE-4, Schedule 22, Line 4.

V. REGULATORY ASSETS/LIABILITIES

Q. Please describe how Regulatory Assets/Liabilities are handled under Schedule 23 of the formula rate.

A. As discussed by Mr. Hansen, the purpose of this cost category is to provide a mechanism for any regulatory assets/liabilities created by ratemaking actions of regulatory agencies to be recovered through transmission rates. All Commission approved regulatory assets and liabilities are summarized in Schedule 23 of the proposed Formula Rate.

Q. Are there any changes to the treatment of Regulatory Assets/Liabilities under the proposed Formula Rate relative to the Original Formula Rate?

A. No.

Q. Please describe the regulatory asset/liability inputs under Schedule 23.

A. Schedule 23 lists the Commission approved asset/liability, approval order reference, the beginning and end of year balance, as well as the amortization amount authorized in the Prior Year.

Q. Are there any exceptions to what assets/liabilities are reported under Schedule 23?

A. Yes. Schedule 23 excludes any Abandoned Plant costs recovered under Schedule 12.

Q. What are the regulatory asset/liability inputs for 2016 reflected in the proposed Formula Rate?

A. For the proposed Formula Rate, there are no regulatory assets/liabilities to be reported under Schedule 23 for 2016.

VI. TRANSMISSION WAGES AND SALARY ALLOCATION FACTOR

Q. Please describe the Transmission Wages and Salary Allocation Factor.

A. The Transmission Wages and Salaries Allocation Factor ("Labor Allocator") is a labor ratio derived by dividing ISO Transmission Wages and Salaries by total Wages and Salaries. This calculation is exclusive of A&G related Wages and Salaries. The Labor Allocator is used in the proposed Formula Rate to allocate certain costs to ISO ratepayers.

Q. Are there any changes to the treatment of the Labor Allocator under the proposed Formula Rate relative to the Original Formula Rate?

A. No. However, the proposed Formula Rate treats Non-Officer Incentive Compensation ("NOIC") differently than the Original Formula Rate. This difference is discussed in more detail by Mr. Mindess in Exhibit SCE-12. As discussed below, NOIC is an input to the calculation of the Labor Allocator.

Q. Please describe how the ISO Transmission Wages and Salary is calculated.

A. ISO Transmission Wages and Salary is derived from Schedule 19 – Operations and Maintenance. This schedule determines the total transmission and distribution labor that is attributable to ISO. Schedule 19 is described in more detail in the testimony of Mr. Moon, Exhibit No. SCE-9. This value is the numerator of the Labor Allocator.

Q. Please describe how total Wages and Salary is calculated.

A. This calculation begins with total Wages and Salary as reported in FERC Form 1. Second, A&G related Wages and Salaries, also as reported in FERC Form 1, is subtracted. Third, non-A&G departmental NOIC is added to the total since this type of expense is not reported as departmental Wages and Salaries in FERC Form 1. The final result is total non-A&G Wages and Salaries, inclusive of NOIC. This value is the denominator of the Labor Allocator.

Q. What is the Labor Allocator for 2016 under the proposed Formula Rate?

A. For the proposed Formula Rate, the 2016 Labor Allocator is 6.1650%. The detail calculation is shown on Lines 1-9 of Schedule 27.

VII. TRANSMISSION PLANT ALLOCATION FACTOR

Q. Please describe the Transmission Plant Allocation Factor.

A. The Transmission Plant Allocation Factor ("Plant Allocator") is a plant ratio derived by dividing Total Plant In Service attributable to ISO by Total Plant In Service. The Plant Allocator is used in the proposed Formula Rate to allocate certain costs to ISO ratepayers.

Q. Are there any changes to the treatment of the Plant Allocator under the proposed Formula Rate relative to the Original Formula Rate?

A. No.

Q. Please describe how Total Plant In Service attributable to ISO is calculated.

A. Total Plant In Service attributable to ISO is equal to the sum of four components, (1) Transmission Plant – ISO, (2) Distribution Plant – ISO, (3) Electric Miscellaneous Intangible Plant – ISO, and (4) General Plant – ISO.

Q. Please describe how Transmission Plant – ISO is calculated.

A. Transmission Plant – ISO is derived from Schedule 7 – Transmission Plant Study Summary. This schedule summarizes the results of SCE's Plant Study, and presents the total transmission plant that is attributable to ISO. SCE's Plant Study and Schedule 7 of Exhibit No. SCE-4 are described in more detail in the testimony of Mr. Moon, Exhibit No. SCE-9.

Q. Please describe how Distribution Plant – ISO is calculated.

A. Like Transmission Plant ISO, Distribution Plant – ISO is derived from Schedule 7 – Transmission Plant Study Summary. Note that currently there are no distribution plant assets attributable to ISO.

Q. Please describe how Electric Miscellaneous Intangible Plant – ISO is calculated.

A. Electric Miscellaneous Intangible Plant ISO ("ISO Intangible Plant") is derived by multiplying Total Electric Miscellaneous Intangible Plant ("Intangible Plant") by the Labor Allocator. Intangible Plant is derived from Schedule 6 – Plant In Service. Among other things, this schedule summarizes the end of year Intangible Plant balance. Schedule 6 is described in more detail in the testimony of Mr. Gunn, Exhibit No. SCE-7.

Q. Please describe how General Plant – ISO is calculated.

A. General Plant - ISO is derived by multiplying Total General Plant by the Labor Allocator. General Plant is derived from Schedule 6 – Plant In Service. Among other things, this schedule summarizes the end of year Total General Plant balance. Schedule 6 is described in more detail in the testimony of Mr. Gunn, Exhibit No. SCE-7.

Q. Please describe how Total Plant In Service is determined.

A. The Total Plant In Service value is as reported in FERC Form 1.

Q. What is the Plant Allocator for 2016 under the proposed Formula Rate?

A. For the proposed Formula Rate, the Plant Allocator is 19.3143%. The detail calculation is shown on Lines 14-22 of Schedule 27 of Exhibit No. SCE-4.

Q. Does this conclude your testimony?

A. Yes, it does.

AFFIDAVIT of AUTHENTICATION

State of California)

) ss

County of Los Angeles)

Antonio Ocegueda, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Antonio Ocegueda

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Antonio Ocegueda, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF ROBERT A. THOMAS

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-16)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

SUMMARY OF THE PREPARED DIRECT TESTIMONY OF ROBERT A. THOMAS

(EXHIBIT SCE-16)

Mr. Thomas discusses the methods used to develop the Retail Level transmission rates factors, as performed in Schedule 33 of SCE's proposed Formula Rate Spreadsheet. The testimony includes a discussion on the development and application of the 12 months of coincident peak (12-CP) allocation factors for Retail Base TRR revenue allocation, followed by a discussion on the billing determinants and rate design. Customers with on-site generation resources are served on standby rates, which are now reflected in their respective retail rate groups for purposes of revenue allocation and rate setting. Mr. Thomas also provides factors to use in the True Up Adjustment in the event a partial year true up is necessary. Finally, Mr. Thomas supports the retail aspects of cost of Service Statements BG, BH, and BL.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF ROBERT A. THOMAS ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Robert A. Thomas, and my business address is 8631 Rush Street, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Manager of Rate Design in the Regulatory Affairs Organization at Southern California Edison Company. In this position, I am responsible for the development of SCE's retail level rate designs. I have held this position since November 20, 2006.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's of Science and Engineering from the University of Arizona, a Professional Engineer License in Mechanical Engineering, and a Masters in Business Administration from California State Polytechnic University, Pomona. Prior to my present position, my responsibilities have included Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was SCE's

Program Manager for the Self Generation Incentive Program ("SGIP"). In this position I was responsible for all aspects of the program including processing of applications, promotion of the program, and dispute resolution. I was also SCE's lead representative on the SGIP Working Group.

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in SCE's 2012, 2013, 2014, 2015, 2016, and 2017 Reliability Services filings (Docket Nos. ER12-201, ER13-227, ER14-222, ER15-216, ER16-174, and ER17-232), and in SCE's TO4, TO5, and TO6 transmission rate case proceedings (Docket Nos. ER08-1343, ER09-1534, and ER11-3697). I also submitted testimony in SCE's Formula Rate Revisions (Docket Nos. ER16-1292-000, and ER16-1393-000).

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe SCE's proposed formula for designing retail rates to recover the Base Transmission Revenue Requirement ("Base TRR") as set forth in Schedule 33 of the proposed Formula Rate Spreadsheet, (Exhibit SCE-4). My testimony will address:

- The formula methodology for allocating the Base TRR to retail rate groups based on each group's load contribution to the system coincident peak demand over 12 months ("12 months of coincident peak" or "12-CP");
- Determination of the component level rate factors (i.e., demand and energy charges) for each rate schedule based on the 12-CP revenue allocations;
- The Formula Rate treatment of standby and station load customers in the development of proposed retail transmission rates for these customer groups and;

- The retail aspects of SCE's Statements BG, BH, and BL.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring Schedule 33 (Retail Rates).

II. OVERVIEW OF SCE'S RETAIL RATE CALCULATION METHODOLOGY

Q. How does the proposed Formula Rate determine the retail transmission rates?

A. Retail rates are developed in Schedule 33 of the proposed Formula Rate Spreadsheet (Exhibit SCE-4). Schedule 33 determines the retail transmission rates by first allocating the Retail Base TRR to retail rate groups based on each group's percentage contribution to the system 12-CP. The retail rate groups are those approved by the California Public Utilities Commission ("CPUC") and will be input into the Schedule 33 when it is updated each year in the Annual Update. Retail transmission rates are then determined for each rate group by applying forecasted billing determinants. Schedule 33 uses the sum of forecast monthly maximum demands (kW) for demand metered customers; forecast annual energy (kWh) usage for non-demand metered customers; and the sum of monthly recorded standby kW demands for standby customers with on-site generation.

Q. Please describe the design methodology for determining the 12-CP allocation factors.

A. The proposed Formula Rate uses the 12-CP methodology to allocate the Base TRR across the retail rate groups. To develop the 12-CP rate group level allocation factors, Schedule 33 averages the most recently available 3-year load research data to calculate the 12 months of coincident peak demand for each rate group. The resulting 3-year average of the 12 monthly coincident peak demand, by retail rate group is then adjusted for distribution losses to derive 12-CP data for each rate group at the meter level. The loss adjusted

12-CP data are further adjusted to account for forecasted sales. This additional step minimizes the impact associated with large customer migrations between rate groups. The 12-CP percent allocation factors, by retail rate groups are then determined by dividing each rate group's proportional contribution to the loss adjusted 3-year average system peak demands. This calculation is performed in Schedule 33 on Lines 35a through 36, Columns 1 through 11 of Exhibit SCE-4.

Q. Please describe the design methodology for determining the revenue allocation by retail rate group.

A. To perform the Base TRR revenue allocation, the 12-CP allocation percentages, by retail rate group are then multiplied by the Retail Base TRR to determine each rate group's transmission cost responsibility for rate design purposes. This revenue allocation process is consistent with the current Base TRR allocation method. The calculation is performed in Schedule 33 on Line 1a through 2, Columns 1 through 2 of Exhibit SCE-4.

Q. Please describe the rate design methodology used to develop retail rate levels.

A. The proposed Formula Rate determines retail rates for each Rate Schedule using allocated Retail Base TRR costs, as described above, applied to the specific forecast billing determinants of each rate group. Monthly retail transmission charges are established by dividing allocated costs by the sum of the forecasted monthly billing determinants for the respective rate groups. For the demand metered customers with monthly demand greater than 500 kW where SCE regularly serves their loads, the formula develops a monthly transmission demand rate using the maximum non-time related demands (kW) for the billing cycle (Schedule 33, Lines 9a through 9d, Columns 5 through 8 of Exhibit SCE-4). For energy-only rate groups, where SCE only meters kWh energy consumption, monthly transmission energy charges are developed by dividing the allocated Retail Base TRR by the annual forecasted kWh to produce a $/kWh charge (Schedule 33, Lines 16a through 17, Column 5 of Exhibit SCE-4). The energy only rate groups include the Domestic, GS-1, TC-1, and Street & Area Light rate groups. For customers receiving standby service in demand-metered rate groups, the formula develops retail transmission rates using the monthly recorded standby kW demands for the billing cycle (Schedule 33, Lines 9a through 9d, Columns 1 through 3 of Exhibit SCE-4). For customers with monthly demand less than 500 kW, the formula develops a monthly transmission demand rates using the maximum non-time related kW demands and standby kW demands for the billing cycle (Schedule 33, Lines 16a through 17, Columns 1 through 10 of Exhibit SCE-4).

III. DERIVATION OF SCE'S BILLING DETERMINANTS USED IN CALCULATING RETAIL TRANSMISSION RATES

Q. What are SCE's forecasted sales levels used in this filing to calculate retail rates?

A. SCE's retail sales at the meter level are 83,227 GWh, as reflected by the sum of the GWh on Line 2, Columns 3 and 4. This is based on SCE's latest corporate approved forecast filed in SCE's ERRA proceeding at the CPUC.

Q. How does SCE derive forecast billing determinants consistent with the aggregate retail sales forecast?

A. SCE first forecasts the number of customers and sales by revenue class, i.e., residential, commercial, industrial, agricultural and other public authorities. These broad classifications tend to be stable over time, and general economic and demographic data for them are commonly available. A normalized forecast of billing determinants by rate group, which matches the revenue class sales forecast in total, is then developed. The reason billing determinants are not forecast independently of the revenue class sales is that rate groups are not as stable as revenue classes, as customers tend to switch rate groups over time, and statistical analyses that capture general economic trends, such as expansions and recessions, are difficult to perform on rate group data without the demographic and economic data commonly available by revenue class.

In Docket No. ER16-1292, submitted on March 30, 2016, SCE requested transmission retail rate revisions to account for the transmission revenue impact caused by the CPUC authorized Net Energy Metering ("NEM") program. This request, accepted by letter Order issued on May 20, 2016, revised the calculation Transmission retail rates to ensure that rates appropriately reflect retail transmission charges not assessed to a portion of retail delivered energy as a result of the NEM program. The change was incorporated in the calculations of the formula rate in Schedule 33 on Lines 1a through 2, Columns 3 through 8 of Exhibit SCE-4.

A. Yes. There is one additional aspect of the proposed Formula Rate that I have provided. The proposed Formula Rate includes "Partial Year TRR Attribution Allocation Factors" to be used in the True Up Adjustment calculation in the event that a partial year True Up Adjustment must be performed. These are 12 monthly factors that sum to 100% which represent SCE's normal base transmission revenue recovery pattern over the 12 months of the year. The factors represent a three year average of monthly recorded retail base transmission revenue streams. They are shown in Schedule 3 of the proposed Formula Rate Spreadsheet, Lines 37-52, in Exhibit SCE-4. Mr. Hansen explains how these TRR Attribution Allocation Factors would be used in Exhibit SCE-3.

IV. <u>COST OF SERVICE STATEMENTS</u>

Q. Are you supporting any cost of service statements?

A. Yes, I am supporting the retail aspects of Statements BG (revenues at proposed rates), BH (revenues at present rates), and BL (proposed rates). Mr. Hansen in Exhibit SCE-3 supports the wholesale aspects of these three cost of service statements.

Q. How do you determine the retail information provided in Statements BG and BH?

A. For Statement BG (revenues at proposed rates), I apply SCE's proposed January 1, 2018 retail transmission rates, as stated in Exhibit SCE-4, to the forecast billing determinants used to calculate the transmission rates, on a monthly basis. For Statement BH (revenues at present rates), I apply SCE's present base retail transmission rates to these same forecast monthly billing determinants for 2018.

Q. Does this conclude your testimony?

A. Yes, it does.

<u>AFFIDAVIT of AUTHENTICATION</u>

State of California)

) ss

County of Los Angeles)

Robert A. Thomas, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Robert A. Thomas

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 23rd day of October, 2017 by Robert A. Thomas, proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
DR. PAUL T. HUNT

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

(EXHIBIT SCE-17)

OCTOBER 2017

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company	)))	**Dkt. No. ER18-______-000**

SUMMARY OF THE
PREPARED DIRECT TESTIMONY OF
DR. PAUL T. HUNT

(EXHIBIT SCE-17)

Dr. Hunt's testimony supports Schedule 5 of Southern California Edison's ("SCE") proposed formula rate, which determines the components of the capital structure, including associated costs of debt and preferred stock that are incorporated in the transmission revenue requirement. In addition, his testimony supports SCE's proposed Return on Equity ("ROE"). The proposed ROE is comprised of a base ROE of 10.30 percent plus a Commission-approved adder for SCE's membership in the California Independent System Operator Corporation ("CAISO") of 0.50 percent. The base ROE is supported by the analysis in this exhibit and Exhibit Nos. SCE-18 through SCE-21.

Further, Dr. Hunt explains that several SCE transmission projects have Commission-approved project-specific adders, which are added to the proposed ROE. Dr. Hunt's testimony shows that the resulting project-specific ROEs are contained within the zone of reasonableness that the Commission should adopt in this docket.

Dr. Hunt also provides ROE estimations using other methodologies and benchmarks, including the Capital Asset Pricing Model (CAPM), empirical (e)CAPM, and comparable earnings model. In addition, Dr. Hunt explains the anomalous economic conditions which have caused the current interest rates to remain below equilibrium levels.

PREPARED DIRECT TESTIMONY OF
DR. PAUL T. HUNT
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

PREPARED DIRECT TESTIMONY OF
DR. PAUL T. HUNT
ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

Q. Please state your name and business address for the record.

A. My name is Dr. Paul T. Hunt, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770-3714.

Q. Briefly describe your present responsibilities at Southern California Edison Company ("SCE" or "Edison").

A. I am the Director of Regulatory Finance and Economics in the Treasurer's Department. My present responsibility is to apply economic, financial, and statistical analysis to regulatory issues and for internal corporate purposes.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from Pomona College in 1975, a Master of Arts degree in Economics from Stanford University in 1976, and a Doctor of Philosophy degree in Economics from Stanford University in 1981. I joined SCE as an Associate Economist in the Treasurer's Department in 1980. I was promoted to Economist in 1982 and Senior Economist in 1984. In 1989, I transferred to the Regulatory Policy and Affairs Department as a Regulatory Economics Consultant. I returned to the Treasurer's Department in 1996 as a Senior Economist. In 1997, I was promoted to Project Manager. In 2000, I was promoted to Manager of Regulatory Finance and Economics. I was promoted to my present position in 2010.

In late 2009, I was invited to write, with a co-author, a book chapter on cost of capital in regulated industries. The book chapter is titled “Cost of Capital in Regulated Industries,” and it is found in *Cost of Capital in Litigation: Applications and Examples*, published by John Wiley & Sons, Inc. in November 2010.[1] A revised version of this book chapter appears in *The Lawyer’s Guide to The Cost of Capital: Understanding Risk and Return for Valuing Businesses and Other Investments*, published by ABA (American Bar Association) Publishing in July 2014.[2]

Q. Have you submitted testimony to the Commission previously?

A. Yes. I have submitted testimony in Docket Nos. ER82-427-000, ER84-75-000, ER97-2355-000, ER02-925-000/ER02-925-001, ER03-549-002, EL00-105-007/ER00-2019-007, ER06-186-000, ER08-375-000, ER08-437-000, ER08-1343-000, ER09-187-000, ER09-1534-000/ER09-1534-001, ER10-160-000, ER11-1952-000, and ER11-3697-000. I have also submitted affidavits in Docket Nos. ER04-316-000, ER08-375-004, ER09-187-002/ER10-160-000, EL10-1-000, EL10-81-000, EL11-10-000, and EL17-63-000. My previous testimony has generally concerned issues related to cost of capital and cost escalation. I have also submitted testimony to the California Public Utilities Commission (“CPUC”) on behalf of Southern California Edison Company.

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1 ISBN: 978-0-470-88094-4.

2 ISBN: 978-1-62722-723-0.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: 1) explain SCE's formula for determining the components of the capital structure, including associated costs of debt and preferred stock, 2) support SCE's proposed base Return on Equity (ROE) of 10.30%, 3) explain why Opinion 531's two-step Discounted Cash Flow (DCF) model is inadequate in determining SCE's authorized ROE, and 4) provide financial benchmarks and other analyses to support the proposed ROE.

Q. Can you please provide a summary of your testimony?

A. Section II provides details on how the debt and preferred stock components of the capital structure are calculated.

Section III provides SCE's proposal on our recommended formula to calculate the ROE, not including project specific adders, of 10.80%. This ROE is composed of a base ROE of 10.30 percent and a 0.50 percent adder to the base ROE to compensate SCE for its membership in the California Independent System Operator Corporation ("CAISO").

Section IV provides the basis for SCE's proposal on our recommended base ROE of 10.30%. The proposed base ROE of 10.30% is based on the expanded two-step DCF model, the California Public Utilities Commission (CPUC) authorized ROE for SCE for 2018 and 2019,[3] and the unique risks that SCE faces as a public electric utility operating in California. The ROE request is supported by multiple financial models including the Capital Asset Pricing Model (CAPM), the empirical (e)CAPM, and the comparable earnings model.

Section V provides a regulatory background on the estimation of ROE.

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[3] 2019 ROE is subject to the trigger of the cost of capital mechanism. The mechanism is based on an interest rate benchmark. Current projections show that an upward trigger is possible, but unlikely. An upward trigger would result in a higher ROE. For details, please refer to D.17-07-005, P. 4.

Section VI provides an explanation of the limitations and deficiencies of Opinion 531's two-step DCF model, which when applied to SCE, results in ROE estimates that are too low to be just and reasonable.

Section VII presents SCE's expanded two-step DCF model and its results. The expanded two-step DCF model only modifies some of the input assumptions of Opinion 531's two-step DCF model but leaves the main structure in place. The section also explains how the expanded two-step DCF model provides ROE estimates that are just and reasonable.

Section VIII presents the results of Opinion 531's two-step DCF model as a reference point.

Section IX provides financial benchmarks that support SCE's ROE request.

Section X provides an explanation of anomalous capital market conditions and how the current economic environment has not returned to normal conditions since the 2008 recession.

Section XI summarizes the selection of the requested ROE within the zone of reasonableness.

Q. What portions of the Formula Rate Spreadsheet will you be sponsoring?

A. I am sponsoring the following portions of Exhibit No. SCE-4: Schedule 1, Lines 37-56 relating to return and capitalization calculations and Schedule 5 (including parts ROR-1, ROR-2, ROR-3, and ROR-4 all relating to capital cost calculations).

II. <u>THE RETURN ON CAPITAL</u>

Q. What parts of SCE's proposed Formula Rate are you sponsoring?

A. I am sponsoring Schedule 5 of Exhibit No. SCE-4, which determines the return on capital information that is used in other parts of the proposed Formula Rate.

Q. What are the elements of the return on capital?

A. The return on capital includes the proportions of long-term debt, preferred equity, and common equity that finance SCE's rate base, also known as the capital structure, plus the costs of long-term debt, preferred equity, and common equity.

The capital structure is based on recorded FERC Form 1 debt and preferred equity balances and associated recorded FERC Form 1 data with certain adjustments that I describe below. The costs of long-term debt and preferred equity are determined based on recorded FERC Form 1 data and SCE's internal records, using the methods prescribed for Statement AV in the Commission's regulations. The cost of common equity is determined in the formula based on SCE's annual percentage cost of equity, developed as discussed below, applied to SCE's recorded amount of common equity from FERC Form 1.

Q. How are the percentages of long-term debt, preferred equity, and common equity determined in the formula?

A. The percentages are based on 13-month averages for SCE's long-term debt, preferred equity, and common equity of the Prior Year.[4]

Q. How do you calculate the cost of long term debt?

A. The cost of long term debt is calculated consistent with the instruction in Statement AV, which states, "The utility shall show the following for each class and series of long term debt outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II.

"(1) Title;

"(2) Date of offering and date of maturity;

"(3) Interest rate;

"(4) Principal amount of issue;

"(5) Net proceeds to the utility;

"(6) Cost of money, which is the yield to maturity at issuance based on the interest rate and net proceeds to the utility determined by reference to

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4 The Prior Year is the most recent calendar year at the time an annual Informational Filing is submitted to the Commission. For a complete explanation of the Prior Year, please see Mr. Hansen's testimony in Exhibit No. SCE-3.

any generally accepted table of bond yields;

"(7) Principal amount outstanding;

"(8) Name and relationship of issuer and if the debt issue was issued by an affiliate; and

"(9) If the utility has acquired at a discount or premium some part of the outstanding debt which could be used in meeting sinking fund requirements, or for some other reason, the annual amortization of the discount or premium for each issue of debt from the date of the reacquisition over the remaining life of the debt being retired. The utility shall show separately the total discount and premium to be amortized, and the amortized amount applicable to Period I and, if applicable, Period II."[5]

Q. How do you calculate the cost of preferred stock?

A. The cost of preferred stock is calculated consistent with the instruction in Statement AV, which states, "the statement shall show for each class and issue of hybrid and preference stock outstanding as of the end of Period I, as expected on the date the changed rate is filed, and, if applicable, as estimated to be outstanding as of the end of Period II:

"(1) Title;

"(2) Date of offering;

"(3) If callable, call price;

"(4) If convertible, terms of conversion;

"(5) Dividend rate;

"(6) Par or stated amount of issue;

"(7) Net proceeds to the filing utility;

"(8) Ratio of net proceeds to gross proceeds received by the filing utility;

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5 18 CFR § 35.13(h)(22)(ii)(B), p. 293 (April 1, 2017 Edition).

"(9) Cost of money (dividend rate divided by the ratio of net proceeds to gross proceeds for each issue);

"(10) Par or stated amount outstanding; and

"(11) If issue is owned by an affiliate, name and relationship of owner."[6]

Q. Where is the calculation for cost of long term debt and cost of preferred stock shown?

A. The cost of long term debt is shown in Schedule 5-ROR-3 of Exhibit No. SCE-4. The cost of preferred stock is shown in Schedule 5-ROR-4 of Exhibit No. SCE-4.

Q. Is the calculation of cost of long term debt and cost of preferred stock consistent with the method used in the Original Formula Rate?

A. No. In the Original Formula Rate, the cost of long term debt is equal to the sum of interest on long-term debt and the amortization of debt discount and expense; the cost of preferred equity is the sum of dividends, amortization of net gain (loss) from purchase and tender offers, and the amortization of issuance costs.

Q. Why did SCE change the calculation of its cost of long term debt and cost of preferred stock in this filing?

A. SCE updated the calculation of its cost of long term debt and cost of preferred stock in this filing so it reflects the yield-to-maturity method outlined in Statement AV.

Q. Are the calculation of the <u>amount</u> of long term debt and preferred stock consistent with previous filings?

A. Yes, the calculation of the <u>amount</u> of long term debt and preferred stock is the same as previous filings. The amount of long term debt is calculated by using the bond balance in Account 221 plus several adjustments explained below. The amount of preferred stock is calculated by using the preferred stock amount in Account 204 plus several adjustments explained below.

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6 18 CFR § 35.13(h)(22)(iii)(B), p. 293 (April 1, 2017 Edition).

Q. What adjustments are included in your calculations of these amounts?

A. The adjustments recognize two important facts: (1) certain SCE long-term debt issues do not finance rate base and should not be included in the calculation of long-term debt; and (2) rate base can only be financed with the net proceeds of SCE's financing activities, so that the amounts of long-term debt and preferred equity that are included in the calculation of the capital structure are less than the amounts of long-term debt and preferred equity that are outstanding and recorded in SCE's FERC Form 1.

Q. What SCE long-term debt does not finance rate base?

A. Series 2014C, and part of Series 2015A and Series 2015B do not finance rate base.

Series 2014C bonds were issued for the purpose of financing SCE's fuel inventories.[7] SCE's fuel inventories are not part of SCE's FERC-jurisdictional rate base, and SCE is not permitted to use the proceeds from these bonds to finance operating expenses or capital additions. Therefore, the Series 2014C bonds should be excluded from any capital structure calculation in the formula. Interest costs and amortizations associated with these bonds are also excluded from any formula calculations.

Series 2015A and Series 2015B bonds were issued in January 2015 to finance the San Onofre Nuclear Generation Station (SONGS) regulatory asset authorized by the CPUC's November 2014 Decision 14-11-040. The referenced

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[7] The Series 2014C bonds were issued pursuant to authority granted by the CPUC in D.14-02-021. The decision permits SCE to issue one or more series of debt securities and states in part: "Use the proceeds from the Debt Securities for the following purposes only: (i) pay accrued interest and expenses incident to the issuance of the Debt Securities; (ii) finance diesel, natural gas, and nuclear fuel inventories; (iii) retire or refund $400 million of debt securities issued previously to finance fuel inventories pursuant to Decision 03-11-018; and (iv) reimburse SCE for money it has expended from its income, or from funds in its treasury that are not secured or obtained from the issuance of debt or equity, for the aforesaid purposes except maintenance of service and replacements. The amounts so reimbursed shall become a part of SCE's general treasury funds." D.14-02-021, Ordering Paragraph 1b.

CPUC Decision "provides that each Utility would be allowed to exclude the [SONGS] Base Plant regulatory asset from future measurements of its ratemaking capital structure."[8] This amount will be recovered at a reduced rate of return over ten years, from 2012 to 2022. The amount of the bonds that are in excess of the regulatory asset that finances rate base is included in the calculations.

Therefore, the Series 2014C, and part of 2015A, and 2015B bonds should be excluded from any capital structure calculation in the formula. Interest costs and amortizations associated with these bonds are also excluded from any formula calculations.

Q. When do the 2014C, 2015A, and 2015B bonds mature?

A. Series 2014C is scheduled to mature November 2017. Series 2015A and Series 2015B are scheduled to mature February 2022.

Series 2015A has an amortizing structure that matches the amortization of the regulatory asset. Series 2014C and 2015B have a standard structure with a balloon payment at maturity. SCE can redeem these bonds before the maturity date. If SCE redeems the 2014C, 2015A, and/or 2015B bonds, refunds them at maturity, or adds additional long-term debt for any other purpose than financing FERC-jurisdictional rate base, SCE will update the formula calculation appropriately in the annual update process.

Q. Please explain your comment that rate base can only be financed with the net proceeds of SCE's financing activities.

A. Issuing long-term debt and preferred equity causes SCE to incur three types of costs: discounts or premiums, expenses, and (in some cases) losses on reacquired debt or preferred equity. These costs are not recovered through operations and maintenance expense, instead they are amortized over the life of the associated security. The amount that is available to finance rate base is the face value of the

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8 D.14-11-040, p. 24.

security *less* the unamortized amount of these costs.

Q. Why must one take account of unamortized expenses, discounts/premiums, and losses on reacquired securities to correctly calculate the amount of debt and preferred equity in the capital structure?

A. If one does not take account of these items, then the utility, SCE in this case, will not recover its full cost of capital. I provide an example in Exhibit SCE-21 that substantiates this point.

Q. Please summarize Exhibit SCE-21.

A. Exhibit SCE-21 shows that if the cost of capital is calculated without reference to unamortized expenses and discounts, the resulting weighted average cost of capital, when applied to the rate base, will not be sufficient for the utility to recover its total capital cost, including interest costs and the amortization of expenses and discounts. Although the case of unamortized losses on reacquired debt or preferred equity is not shown in this example, the results would be the same.

Q. What is the key to Exhibit SCE-21?

A. The key is that the rate base cannot exceed the net proceeds from debt and equity issuance. If the weighted average cost of capital ("WACC") is calculated using the book value of equity and the face value of debt, then it will be insufficient to recover the total capital costs of the company. The total cost of capital is calculated in columns H through J. Columns K through M show that recovery using the book value/face value WACC applied to the rate base will be insufficient to recover the total capital costs. On the other hand, columns N through Q show that using a net proceeds-based WACC applied to the rate base will recover the total capital costs.

Q. Without consideration of adjustments for expenses, discounts/premiums, and losses on reacquired securities, would SCE generally over- or under-recover its cost of capital?

A. Generally, SCE would under-recover its cost of capital, because SCE almost always issues securities at a discount to face value.

Q. Could there ever be a situation where omitting these adjustments could cause SCE to over-recover its cost of capital?

A. Yes, although it is unlikely. If SCE consistently issued securities at a premium to their face values plus expenses, SCE could over-recover its cost of capital. The use of net proceeds avoids this result, just as it avoids under-recovery. Thus, the Commission should adopt the use of net proceeds, which recovers the correct amount of cost.

Q. Why do you employ 13-month calculations in lines 1-7, 10-11, 13-15, and 17-21 of Schedule 5?

A. These lines are associated with the calculation of debt and equity balances. These balances are the denominators in the calculation of the amount of long-term debt and preferred equity. The use of a 13-month average improves the accuracy of the amount of long-term debt and preferred equity outstanding. Given the long-term debt and preferred equity balances are calculated using a 13-month average, the common equity balance must be calculated in the same way to produce a consistent set of capital ratios.

Q. Referring to line 9 in Schedule 5, why do you only include the after-tax amount of Unamortized Loss on Reacquired Debt.

A. The formula assumes that any loss on reacquired debt results in an income tax deduction that is recorded when the loss occurs, so that only the after-tax portion of the loss is unrecovered.

III. <u>SCE'S PROPOSED RETURN ON EQUITY</u>

Q. What is your recommended return on equity ("ROE"), not including project-specific adders, to be incorporated in SCE's proposed Formula Rate and what is it based upon?

A. My recommendation is that the formula ROE, not including project-specific adders, should be 10.80 percent. This ROE is composed of a base ROE of 10.30 percent and a 0.50 percent adder to the base ROE to compensate SCE for its membership in the CAISO as approved by the Commission's Order Granting Petition for Declaratory Order in Docket EL07-62-000.[9]

Q. What project incentive adders have been authorized by the Commission?

A. The Commission has authorized the following project adders:

- Rancho Vista, 0.75 percent;[10]
- Tehachapi, 1.25 percent;[11] and
- Devers-Colorado River, 1.00 percent[12]

The total ROEs for these three projects are 11.55 percent, 12.05 percent, and 11.80 percent, respectively. As discussed below, all of these ROEs are within the zone of reasonableness in the expanded two-step DCF Model.

Additionally, as explained in the testimony of Berton Hansen in Exhibit No. SCE-3, the formula calculates and includes in the Prior Year TRR and the True Up TRR incentive adder components associated with project-specific return on equity adders that have been granted to SCE by the Commission.

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9 *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) at p. 158.

10 *Id.* at P. 129.

11 *Id.* at P. 129.

12 *Southern California Edison Co.*, 132 FERC ¶ 61,213 (2010).

Q. How is the proposed ROE amount of 10.80 percent incorporated in the formula calculation of Return on Capital?

A. The formula states SCE's proposed ROE amount of 10.80 percent on Line 50 of Schedule 1 of Exhibit No. SCE-4. This is within the "Return and Capitalization" calculations sub-piece of Schedule 1, where SCE's total Return on Capital is calculated. The proposed ROE contributes to SCE's Weighted Cost of Common Stock, shown on Line 53 of Schedule 1 of Exhibit No. SCE-4. The Weighted Cost of Common Stock is equal to the Common Stock Capital Percentage shown on Line 47 times the 10.80 percent proposed ROE. This is then added to the Weighted Cost of Long-Term Debt (Line 51) and the Weighted Cost of Preferred stock (Line 52) to derive the Cost of Capital Rate shown on Line 54. This Cost of Capital Rate is then applied to all Rate Base (Line 18) to determine SCE's total Return on Capital (Line 56).

Q. Does the formula calculate the contribution of project-specific ROE adders to SCE's total Return on Equity for in-service plant in the True Up TRR?

A. Yes. This calculation is performed on Schedule 15, Lines 25-39 of Exhibit No. SCE-4. Each year when SCE submits its annual Informational filing, this amount will be recalculated within the formula based on the amount of in-service plant in the Prior Year. In this filing, SCE's project-specific ROE adders have contributed 0.77% to the ROE of Plant In-Service, as shown on Line 36 of Schedule 15 of Exhibit No. SCE-4.

IV. BASIS FOR DETERMINING BASE ROE

Q. What principles form the basis for determination of the base ROE?

A. As set forth by the Supreme Court in a series of legal decisions, including *FPC v. Hope Natural Gas*, 320 U.S. 591, 603 (1944) and *Bluefield Waterworks v. Public Svc. Comm.*, 262 U.S. 679, 692-693 (1923), the ROE authorized for a regulated utility must meet four criteria:

- It must be comparable to returns on investments of similar risk;

- It must be sufficient to ensure confidence in the financial soundness of the utility;
- It must be adequate to permit the utility to be creditworthy; and
- It must allow the utility to attract capital.

Q. What is the basis for SCE's base ROE request of 10.30%?

A. SCE's base ROE request is based on the expanded two-step DCF model, the California Public Utilities Commission (CPUC) July 2017 decision to authorize a 10.30% ROE for SCE for years 2018 and 2019,[13] and the unique risks that SCE faces as a public electric utility operating in California. The ROE request is also supported by the Capital Asset Pricing Model (CAPM), empirical (e)CAPM model, and the comparable earnings model.

Q. Is it reasonable to use state authorized ROEs as a benchmark to determine the reasonableness of the Commission's authorized ROE?

A. Yes. The Commission has consistently found that provision of transmission service is riskier than distribution service. Specifically, Opinion 531 found that, "transmission entails unique risks that state-regulated electric distribution does not."[14] However, the ROE that results from the application of the Opinion 531 prescribed two-step DCF method would be significantly lower than SCE's 2018 and 2019[15] authorized state ROE of 10.30%. Opinion 531 recognized that although the Commission's ROE is not set based on state authorized ROEs, state authorized ROEs are a benchmark to justify shifting the ROE upward. As the

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13 CPUC Decision 17-07-005, Appendix A, p. 1. The ROE for 2019 may change if the cost of capital mechanism triggers. Details on how the mechanism operates can be found on p. 4 of D.17-07-005.

14 147 FERC ¶ 61,234, P. 148.

15 2019 ROE is subject to the trigger of the cost of capital mechanism. The mechanism is based on an interest rate benchmark. Current projections show that an upward trigger is possible, but unlikely. An upward trigger would result in a higher ROE. For details, please refer to D.17-07-005, P4.

Commission stated in Opinion 531:

> The Commission has repeatedly held that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets, because those ROEs are "established at different times in different jurisdictions which use different policies, standards, and methodologies in setting rates." The wisdom of that rationale is no less applicable now than in the Commission's earlier cases. However, in this proceeding, we are faced with circumstances under which the midpoint of the zone of reasonableness established in this proceeding has fallen below state commission-approved ROEs, even though transmission entails unique risks that state-regulated electric distribution does not… Although we are not using state commission-approved ROEs to establish the NETOs' ROE in this proceeding, the discrepancy between state ROEs and the 9.39 percent midpoint serves as an indicator that an upward adjustment to the midpoint here is necessary to satisfy Hope and Bluefield.[16]

Opinion 551 also affirms the consideration of state approved ROEs as an acceptable benchmark for ROE evaluation, stating that "the Commission examines other evidence, namely the results of alternative methodologies and state-commission approved ROEs to assess the reasonableness of the results of the DCF methodology."[17] Although the Commission has stated that it does not establish utilities' ROE based on state commission ROEs for state-regulated electric distribution assets, the discrepancy between low results of the two-step DCF method and state ROEs provides support that an adjustment is necessary in order to result in an ROE that is just and reasonable.

Moreover, were the Commission to establish a base ROE for transmission facilities that is below the authorized ROE for distribution assets, the resulting disparity may cause utility investors to favor construction of distribution facilities over construction of transmission facilities.

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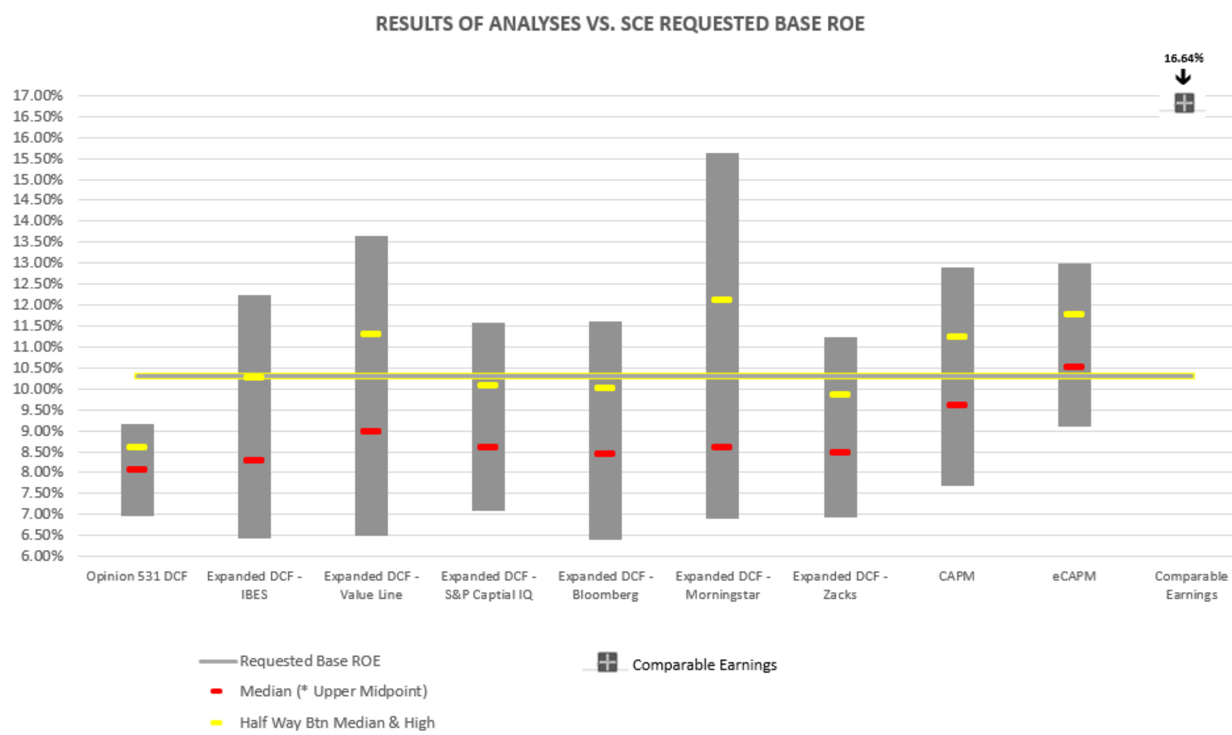
[16] Opinion 531, P. 148.

[17] 156 FERC ¶ 61, 234, P. 125.

Q. What financial benchmarks support the requested base ROE of 10.30%?

A. Cost of capital practitioners use a variety of methods to estimate the ROE. Employing multiple financial models and analyses to estimate the ROE provides greater assurance that a correct result is obtained. SCE's base ROE recommendation is supported by the estimates from the expanded two-step DCF model, the comparable earnings model, the Capital Asset Pricing Model (CAPM), and the empirical (e)CAPM. The methodology and input assumptions of each model is provided in detail in Section VII and IX. The chart below provides a summary of the ROE estimates.



Q. Should the Commission rely only on model results to determine an appropriate ROE for SCE?

A. No. SCE, because it is located in California, faces many risks that are not faced by most of the other electric utilities in the United States. The Commission should take those risks into account in setting SCE's ROE.

Q. In your view, what makes California a risky investment environment?

A. California is in the middle of an industry transformation. The traditional wires infrastructure that is in place focuses on one-way power flow, from central generation to transmission to distribution to end users. Historically, capacity planning centralized around customer load peaks, which are generally the highest during late afternoon or early evening. But needs and planning in California are evolving.

This existing grid design is changing as California moves toward a lower carbon energy future. The influx of Distributed Energy Resources (DERs) and growth of renewable energy are causing a profound shift from one-way to two-way power flow, changing the timing and nature of load peaks on the system.

Meanwhile, SCE must do all this safely and maintain reliability. The goal is to operate the grid effectively. Our transmission and distribution systems must be dependable and be adaptable to the proliferation of new technologies.

This energy revolution provides great opportunities, but also presents a significant amount of uncertainty. SCE is ready to embrace the future, but modernizing our grid creates risks for investors.

Q. How do these new technologies change existing grid design and operation?

A. Distributed Energy Resources (DERs) – such as rooftop solar panels, energy storage, and other energy management systems – are creating a profound shift from centralized generation to distributed generation. The grid and technology we have in place is not fully able to handle these new demands; we need to align our energy future with new infrastructure to handle two-way power flow. Integrating distributed generation with our transmission system is capital intensive and complicated, but it is necessary to achieve operational flexibility.

Additionally, SCE's investors face uncertainties related to implementation of a new Renewables Portfolio Standard (RPS) for California. In April 2011, Governor Edmund G. Brown, Jr. signed Senate Bill X1-2, which requires electric utilities to procure 33 percent of their electricity from renewable energy sources by 2020. This was superseded by Senate Bill 350 signed by the same governor in October 2015, which increased the previous goal for renewable resources to 50 percent by 2030. Then in March 2017, the state Senate, the Assembly Natural Resources Committee and the Assembly Utilities and Energy Committee passed Senate Bill 100, which moves the 55 percent goal up to 2026, sets a 60 percent goal for 2030, and establishes 100 percent goal for 2045. While Senate Bill 100 did not reach a vote this year, the legislature has the opportunity to revisit this bill again next year. These increasingly ambitious policy goals require California utilities to address intermittency of generation and excess generation peaks. Adding to the uncertainty is the new federal administration, where reversal of progressive environmental policies is possible and can be immediate. Working with these goals and potential policy changes creates uncertainty in the planning space.

Q. How do grid changes create risks for SCE's investors?

A. While SCE is embracing this industry transformation, we are facing major risks. Replacing aging infrastructure is necessary but risky. Many of SCE's distribution and lower voltage transmission facilities were installed during the high growth period subsequent to the end of World War II. These facilities are now reaching the end of their useful life, and SCE expects that without major new investments to replace this aging infrastructure, failure rates will increase.

However, replacing aging infrastructure is a challenge in itself when the requirements that the electric system must meet are changing. The proliferation of distributed resources may modify the existing scope of SCE's transmission business. The transmission assets designed under present paradigms are evolving. The rate of technology advancement is exponential, and it is difficult to forecast the future role of the transmission projects that are in development, which complicates future transmission planning. As a result of rapid changes, a project that is deemed necessary today may be revisited before it can go into service.

For example, in its 2016-2017 Transmission Plan,[18] the CAISO reassessed the need for the Gates-Gregg 230 kV transmission project located in Pacific Gas and Electric Company's service territory – previously approved in 2013 – based upon a lower energy and demand forecast, including an increase in behind the meter PV generation.[19] The CAISO found that the economic savings are not presently sufficient to justify the cost of the project and recommended that no further development action of the project be taken until its review is completed. In addition, in that same 2016-17 Transmission Plan,[20] the CAISO performed a review of previously approved projects as a result of changes in the load forecasts and determined that thirteen transmission projects are no longer required based on reliability and local capacity requirements and deliverability assessments.[21] The CAISO's analysis included sensitivities with respect to behind the meter PV and additional achievable energy efficiency.

As another example, SCE's Coolwater-Lugo Transmission Project was cancelled in 2016[22] because the CAISO deemed the project unnecessary after reassessing its need several years into its development. SCE had to abandon the project for reasons beyond its control, even though it had already incurred significant costs in attempting to license and develop the project.

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[18] 2016-2017 Transmission Plan, *California ISO*, March 17, 2017, Board Approved http://www.caiso.com/Documents/Board-Approved_2016-2017TransmissionPlan.pdf , downloaded 10/10/2017.

[19] *Ibid*, p. 104.

[20] *Ibid*, p. 104.

[21] *Ibid*, p. 102.

[22] Docket No. ER16-1025.

These examples demonstrate that some transmission projects are at risk for multiple jurisdictional approvals, significant environmental reviews, technological changes, and long licensing and permitting processes. If transmission projects run into major difficulties, these investments can be postponed or cancelled. In other words, the usefulness of planned or projects that are not yet completed is subject to substantial regulatory risks.

Q. Can the Commission determine an appropriate base ROE by examining only the parts of SCE's utility business that are subject to its jurisdiction?

A. No. SCE's risks are the risks of the enterprise as a whole. SCE does not have financial instruments that solely support transmission assets. With limited exceptions, as discussed above in Section II, SCE's securities support all of SCE's assets and are subject to all of SCE's risks.[23] Many of SCE's risks cannot be reliably allocated to different parts of its business. Thus, any attempt to calculate a transmission business-line-specific risk premium would be a speculative exercise.

Investors are well aware of SCE's history and the risks that attach to its securities. Even though SCE's recent history and current risks have been dominated by events related to power procurement, California regulation, and the California electricity market, SCE's ROE for transmission cannot be set without reference to these events, because SCE's transmission assets are financed with securities that are subject to these events and associated risks.

As a hypothetical example, if SCE and the CPUC had not reached a settlement after the energy crisis of 2001 and SCE had been forced into bankruptcy as a result of debts related to procurement, all of SCE's assets, including transmission assets, would have been at risk to satisfy the demands of

23 The fuel inventory debt and SONGS regulatory asset debt finance only the assets that they are assigned to, but they are serviced out of the cash flow created by SCE's entire business. Were SCE to default on any of its other financial instruments, the creditworthiness of these instruments would be harmed as well.

creditors. In fact, some of the rescue plans that were proposed during SCE's financial crisis contemplated a sale or transfer of SCE's transmission assets to provide cash to pay its procurement obligation.

Q. Are there risks peculiar to SCE's transmission assets that should also be taken into account in setting its cost of capital?

A. Yes. While SCE's cost of capital is a function of its overall enterprise risk as perceived by investors, there are some identifiable components of that risk that are directly related to its transmission assets and the services they provide to wholesale and retail customers. Because this proceeding intends to ensure SCE receives an adequate return on its transmission investment, it is appropriate to highlight the risks unique to that investment. These transmission-specific risks can create a disincentive for additional transmission-related capital expenditures. Providing a fully-compensating return counters this disincentive, and also ensures that SCE's transmission customers pay for the effect of risks that are directly attributable to the service they are using.

Q. Please describe the risks currently associated with the ownership of transmission assets.

A. First, there are generic transmission risks which probably affect all owners given the movement toward electric utility deregulation and Transmission Organizations.[24] Second, there are certain risks unique to the California electricity market and uncertainty associated with actions taken by the CAISO.

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24 Unless otherwise indicated, "Transmission Organization" refers to "a Regional Transmission Organization, Independent System Operator, independent transmission provider, or other transmission organization finally approved by the Commission for the operation of transmission facilities." Federal Power Act §215(a)(6), 16 U.S.C. §824o(a)(6), enacted by Energy Policy Act of 2005, §1211(2005).

Q. Describe transmission-related risk from an industry-wide perspective.

A. Operation of electric transmission networks throughout the United States has been transferred from their utility owners to independent entities. Utilities in California, New York, the Pennsylvania-New Jersey-Maryland area, New England, the Midwest, Texas, and parts of the Southwest have joined Transmission Organizations. Congress has indicated its support for the further development of Transmission Organizations in the Energy Policy Act of 2005. There are risks associated with this structure.

First, whenever asset ownership is separated from operational control, there is an increased risk that the asset owner will face unanticipated costs due to actions taken by the entity with operational control. The entity charged with control will have smooth operations and reliability as its objectives and will not face the cost consequences of its decisions. As a non-profit corporation, the CAISO has been allowed by the Commission to pass on its costs to Participating Transmission Owners ("PTOs"), including SCE, with no assurance that the PTOs have the ability to recover these costs from customers. Second, based on SCE's experience with the CAISO, independent system operators will run the transmission system differently from the way it was run when it was under the control of an integrated utility. SCE's transmission system was originally built for bundled utility dispatch primarily to serve SCE's retail customers. Now it is being used to support market dispatch of unbundled and deregulated wholesale generation. Broadly speaking, transmission assets will be utilized more aggressively when the operator is trying to accommodate the needs of many users, and that will affect operating and maintenance costs.

Q. What are some additional transmission-related risks that SCE faces?

A. SCE's transmission assets have been under the CAISO's operational control for nearly twenty years. Many of the generic risks described above have materialized as actual costs in California. Some may be the result of anomalies unique to the

California market, while others are probably unavoidable given the separation of transmission operation from ownership.

The CAISO has in the past proposed tariff amendments that allocated costs to Scheduling Coordinators (as defined in the CAISO Tariff) and PTOs, such as SCE, without ensuring that such costs were in turn recoverable from customers and/or without providing a clear indication of who should ultimately bear these costs. In the ensuing FERC litigation, the staffs of SCE's regulators and SCE's various customer classes are often at odds with one another, increasing the likelihood that SCE will be unable to recover the costs.

Lawsuits or complaints against the CAISO for negligence, tariff violations, or other wrongdoing could result in costs for Scheduling Coordinators and PTOs, such as SCE, because of the CAISO's non-profit status. Another concern is that CAISO Tariff and Transmission Control Agreement provisions greatly limit the CAISO's liability.

Q. Please summarize the importance of a compensatory rate of return as a transmission investment incentive.

A. To counter risks associated with new transmission investments, the Commission's rate of return authorization must be sufficient to fully compensate utilities for transmission risks. As SCE seeks to improve its financial strength, it will be constantly challenged to make the most of the cash flows available to it. An appropriate return on transmission investments is critical to ensuring that SCE can fund these ongoing capital expenditures.

V. REGULATORY BACKGROUND ON ESTIMATION OF RETURN ON EQUITY

Q. How does the Commission determine the appropriate base ROE?

A. The ROE required by SCE's shareholders cannot be observed directly. It must be estimated by analyzing information about capital market conditions, with reference to the conditions of the particular utility or line of business to which the required ROE pertains.

There are multiple ways to estimate ROE. In Opinion 531, FERC adopted the two-step discounted cash flow (DCF) methodology to estimate the return on common equity.[25] The proceeding started in 2012, based on a complaint under Section 206 of the Federal Power Act (FPA) by customers claiming that the New England Transmission Owners (NETOs) base ROE of 11.14% was unjust and unreasonable. Opinion 531 was issued in June 2014. It established the two-step DCF methodology and set the base ROE at 10.57%, which is the midpoint of the upper half of the zone of reasonableness. In April 2017, the D.C. Circuit Court of Appeals vacated and remanded Opinion 531. Details about the Circuit Court decision are elaborated below.

Q. Please describe the DCF model.

A. The DCF model assumes that a company's stock price is equal to the present value of all expected future cash flows accruing to the company's stock. Mathematically, this can be written as:

$$P = \frac{E(D_1)}{(1+r)} + \frac{E(D_2)}{(1+r)^2} + \frac{E(D_3)}{(1+r)^3} + \cdots \qquad (1)$$

where P is the market price of the stock, $E(D_i)$ is the expected dividend in period i, and r is the required return on equity. Given a stock price and a projection of future dividends, equation (1) can be solved for r.

A simple version of the DCF model requires the additional assumption that dividends grow at the constant growth rate g in all future periods. In this case, equation (1) can be transformed to:

$$P = \frac{E(D_1)}{(1+r)} + \frac{E(D_1)(1+g)}{(1+r)^2} + \frac{E(D_1)(1+g)^2}{(1+r)^3} + \cdots \qquad (2)$$

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[25] *Martha Coakley et al. v. Bangor Hydro-Electric Co. et al.*, Opinion No. 531, 147 FERC ¶ 61,234 (2014) ("Opinion No. 531").

which can in turn be solved to give:

$$r = \frac{E(D_1)}{P} + g \qquad (3)$$

Only one modification remains, which is to provide a formula for $E(D_1)$. The conventional method is to specify that the expected dividend in the next year is a multiple of the most recent annualized historical dividend. Following the Commission's adopted procedure,[26] SCE has calculated the expected dividend as the current dividend multiplied by one-half of the expected growth rate, or, when substituted into equation (3):

$$r = \frac{D(1+0.5g)}{P} + g \qquad (4)$$

Equation (4) is known as the DCF model.

Q. How does the Commission use the DCF method to estimate the ROE?

A. The most recent Commission articulation of an ROE estimation methodology is in Opinion 531. Although it is currently on remand and may not be precedential,[27] in Opinion 531, the Commission selects a proxy group of comparable electric utilities and estimates each company's ROE using the two-step DCF method described above. The ROEs of each company in the proxy group form a range. After eliminating unreasonable low-end estimates, the range forms the zone of reasonableness. The Commission then selects a base ROE within the zone of reasonableness.

Q. What specific criteria does the Opinion 531 two-step DCF method use to identify a proxy group?

A. The Opinion 531 two-step DCF method selects companies for the proxy group of a subject utility by the following criteria:

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[26] Opinion 531, P. 15.

[27] Order Rejecting Compliance Filing, 161 FERC ¶ 61,031 at P. 28.

1. Companies categorized as electric utilities by Value Line Investment Survey;
2. Electric utilities that are within one notch of the subject utility's Standard and Poors (S&P) and Moody's credit rating, when both are available;
3. Utilities currently paying a common stock dividend with dividend payments that are expected to continue.
4. Not involved in major merger and acquisition activity during the period of analysis that would distort DCF results.

Q. How does the Opinion 531 method calculate the growth rate (*g*) in the DCF equation?

A. Opinion 531 calculated a short-term and a long-term growth rate. The short term growth rate is based on the five-year Institutional Brokers' Estimate System (IBES) growth rate projections from *Yahoo! Finance*. The long term growth rate is based on Gross Domestic Product (GDP) projections published by IHS Global Insight, the U.S. Energy Information Administration (EIA), and the Social Security Administration (SSA). The IBES short-term growth rate is weighted two-thirds and the GDP growth rate is weighted one-third to compute a single two-step growth rate for each company in the proxy group.

Q. How does the Commission select the base ROE within the zone of reasonableness?

A. Before Opinion 531, the Commission generally selected a base ROE using the midpoint or the median of the estimates. It would select the median ROE for single utility filers, and the midpoint ROE for group filers.

In Opinion 531, the Commission found that a base ROE set at the middle of the zone was unjust and unreasonable due to anomalous capital market conditions[28] and in view of the results of alternative benchmark analyses. In order to determine a just and reasonable ROE, the Commission authorized the base ROE

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[28] Opinion 531, P. 41 and P. 145.

set at the midpoint of the upper middle half of the zone of reasonableness.

Q. Has there been other court decisions since Opinion 531 that affects that ROE calculation?

A. Yes. On April 14, 2017, the U.S. Court of Appeals for the D.C. Circuit vacated and remanded the Commission's Opinion 531 on two grounds: 1) the Court found that the Commission did not satisfy the burden under FPA's Section 206 to prove that the 11.14% ROE was unjust and unreasonable before defining a new just and reasonable rate; and 2) the Court found that the Commission did not adequately explain the placement of the ROE at the midpoint of the upper half of the zone of reasonableness.[29]

Q. What is the implication of the D.C. Circuit Court decision?

A. Because the D.C. Circuit Court vacated Opinion 531 the two-step DCF methodology may no longer be FERC precedent. The Commission itself recognized this in a related order issued on October 6, 2017.[30] While the DCF method in general is still a reasonable method to estimate ROE, the input assumptions of Opinion 531's two-step DCF methodology are overly inflexible and a mechanical application of the method produces results for SCE that are too low to be just and reasonable.

With Opinion 531 vacated and remanded, the Commission now has an opportunity to address the deficiencies in the two-step DCF inputs that have led to ROEs that are too low to be just and reasonable. SCE identifies the deficiencies below and proposes improved input assumptions that will remedy these issues. SCE's expanded two-step DCF methodology makes modifications to Opinion 531's two-step DCF input assumptions, but preserves the intent of estimating a range of ROEs that satisfies *Hope* and *Bluefield's* standard of estimating a range

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[29] Emera Maine v. FERC, No. 15-1118 (D.C. Cir., Apr. 14, 2017).

[30] Order Rejecting Compliance Filing, 161 FERC ¶ 61,031 at P. 28.

of ROEs that is just and reasonable.

VI. DEFICIENCIES OF OPINION 531'S TWO-STEP DCF METHOD

Q. What are the deficiencies of the Opinion 531's two-step DCF method?

A. The core deficiency of the Opinion 531's two-step DCF method is that the input assumptions lead to a zone of reasonableness for SCE that is too narrow and too low to be just and reasonable. The complete range of estimated ROEs for SCE under the method endorsed in Opinion 531 is from 6.97% to 9.15%, which is too low to satisfy *Hope* and *Bluefield* standards. The authorized base ROE must be commensurate with returns of companies with a similar risk profile. However, the median estimate of 8.06% produced for SCE using the Opinion 531 two-step DCF method is significantly below the current minimum state authorized ROE of 9.2%.[31] Even the top estimate of 9.16% in the zone of reasonableness using the Opinion 531 DCF method is

1) below the minimum state authorized ROE between 2014 and August 2017,
2) below California's authorized ROE of 10.30% for 2018 and 2019,[32] and
3) below the 9.39% ROE that the Commission ruled in Opinion 531 was too low to satisfy *Hope* and *Bluefield*. In short, applying the Opinion 531 methodology here produces results that violate Opinion 531 itself.

Q. What happens if the Commission authorizes an ROE that is too low?

A. Authorizing an ROE that is too low will prevent SCE from attracting the capital that is necessary to finance our transmission infrastructure. Investors will only

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31 SNL Rate Case Statistics, state authorized ROEs for vertically integrated electric utilities, between 2014 – August 2017.

32 SCE's 2019 ROE is subject to the trigger of the cost of capital mechanism. The mechanism is based on an interest rate benchmark. An upward trigger would result in a higher ROE. Current projections show that an upward trigger is possible, but unlikely. For details, please refer to D.17-07-005, p. 4.

provide capital only if they can expect to earn a return on their investment similar to investments of comparable risk. If the authorized ROE is not adequate, investors will not provide the required financing for our capital projects.

Q. You indicated above that the application of the Opinion 531 DCF methodology to SCE creates a zone of reasonableness that is too narrow. What is causing this?

A. The zone of reasonableness produced for SCE under the Opinion 531 methodology is too narrow because the rules in Opinion 531 that determine which companies are included in the proxy group are overly stringent for SCE. Consequently, many companies that are comparable to SCE fall out of the proxy group. Combined with all the merger and acquisition activity that eliminates companies from the proxy group, there are only 10 companies in SCE's proxy group under the Opinion 531 DCF method. The small sample size undermines the reliability of the estimated outcome.

Section VII and Section VIII below give further explanation on the issue of the proxy group size and composition.

Q. Do you have any additional concern with the application of the Opinion 531 methodology to SCE?

A. Yes, I have two concerns. First, the growth rate assumptions used in the model are insufficiently representative of investors' expectations, and second, anomalous capital market conditions are still present.

Under Opinion 531's two-step DCF method, the ROE is estimated by creating a weighted average of two growth rates: IBES for short-term growth rate, and GDP for long-term growth rate. These sources alone, particularly the IBES short-term growth rate, do not capture the full range of investors' expectations for electric utility investment growth. Section VII below gives further explanation on the issue of growth rate assumptions.

In addition, anomalous market conditions that result from the aftermath of the Great Recession have suppressed interest rates in the recent past. Under the DCF method approved in Opinion 531, estimated ROEs that are less than 100 basis points above the utility bond yield are eliminated out of the proxy group as unreasonable. Due to anomalous market conditions, adding 100 basis points to current bond yield of 4.48% for Baa Utility Bonds[33] results in the low-end threshold at 5.48 (4.48+1.00)%**,** which is too low to serve as a reasonable floor for low-end results. Section X below gives further explanation on the issue of anomalous market conditions and the floor for low-end results.

Q. How can the zone of reasonableness be fixed?

A. The zone of reasonableness needs to be expanded in order to produce reasonable results. In addition, the zone of reasonableness needs to be large enough so that it does not limit incentive adders, in the event the Commission continues to cap previously-granted incentives at the high end of zone of reasonableness. SCE is proposing a rational approach that modifies the two-step DCF method in a practical way that will remedy these problems and produce a zone of reasonableness where the Commission can select the base ROE that is just and reasonable.

VII. SCE'S ESTIMATES OF RETURN ON EQUITY BASED ON THE EXPANDED TWO-STEP DCF MODEL

Q. Can you summarize the results of your financial modeling?

A. The SCE expanded two-step methodology gives the following ranges for SCE's cost of common equity for 2018:

[33] Average between February 2017 to July 2017.

Cost of Equity Estimates

Model	Low	Median	Half way between median and high	High
Expanded two-step DCF	6.41%	8.52%	12.08%	15.64%

Q. What were the ROE results of SCE's expanded two-step DCF model?

A. Based on SCE's expanded two-step DCF model, the cost of equity estimates range from 6.41 percent to 15.64 percent with a median of 8.52 percent, and a point midway between the median and top end of the zone of 12.08 percent. The reasonable base ROE should be 10.30%, which is SCE's stated CPUC-authorized ROE for 2018 and is well within the zone of reasonableness.

Q. How does SCE's expanded two-step DCF model differ from the Commission's adopted two-step DCF model?

A. SCE's expanded two-step DCF model expands the zone of reasonableness and enlarges the zone to create a range that is more reflective of investors' diverse expectations and current market conditions. Specifically, it does the following:

1) Increases the proxy group size by including all electric companies that are investment grade.
2) Incorporates more growth rate assumptions that are representative of investors' expectations. This includes using Bloomberg, Morningstar, S&P Capital IQ, Value Line, and Zacks as sources of short-term growth rates <u>in addition</u> to IBES short-term growth rates,
3) Removes unreasonable low-end results by eliminating companies with

ROE estimates that are less than 231[34] points above the cost of debt for each company.

Q. How does SCE's expanded two-step DCF model differ from the Opinion 531 adopted two-step DCF model in the selection of proxy group?

A. The table below summarizes the differences between SCE's expanded two-step methodology and the Opinion 531 two-step methodology:

Proxy Group Selection	**Opinion 531's Two-Step Methodology**	**SCE's Expanded Two-Step DCF Methodology**
Companies	Companies categorized as electric utilities by Value Line Investment Survey	Same as Opinion 531.
Credit Rating Screen	One notch above and below of the subject utility's credit ratings from Standard & Poor's and Moody's. For SCE, this is S&P issuer credit rating of A-, BBB+, and BBB and Moody's issuer credit rating of A1, A2, and A3.	All investment grade electric companies. This is S&P issuer credit rating of BBB- or above or Moody's issuer credit rating of Baa3 or above.
Dividend	Currently paying a common stock dividend and dividend payments are expected to continue.	Same as Opinion 531.
Mergers & Acquisitions (M&A)	Not involved in merger activity or major restructuring during the period of analysis.	Same as Opinion 531.

Q. Please explain how you chose the comparable group for your DCF calculations.

A. My comparable group for the expanded two-step DCF model was selected

34 As explained below in Section VII, 231 basis points is calculated by estimating multiplying the market risk premium by the difference in beta (a measure of risk) between utility bonds and the lowest-risk utility equity.

according to the following criteria:

- Companies categorized as electric utilities by Value Line Investment Survey;
- Companies that are investment grade according to their S&P or Moody's issuer credit ratings;
- Companies currently paying a common stock dividend and dividend payments are expected to continue; and
- Companies not involved in major merger activity or major restructuring during the period of analysis that distorts the DCF inputs.

The comparable companies are Allete Inc., Alliant Energy Corp, Ameren Corp, American Electric Power Company Inc., AVANGRID Inc., Avista Corp, Black Hills Corp, CenterPoint Energy Inc., CMS Energy Corp, Consolidated Edison Inc., Dominion Energy, DTE Energy Company, Duke Energy Corp, Edison International, El Paso Electric Co, Entergy Corp, Eversource Energy, Exelon Corp, FirstEnergy Corp, Fortis Inc., Hawaiian Electric Industries Inc., IDACORP Inc., MGE Energy Inc., NorthWestern Corporation, OGE Energy Corp, Otter Tail Corp, Pacific Gas and Electric Company, Pinnacle West Capital Corp, PNM Resources Inc., Portland General Electric Company, PPL Corporation, Public Service Enterprise Group Inc., SCANA Corporation, Sempra Energy, Southern Co, Vectren Corp, WEC Energy Group, and Xcel Energy Inc.

Q. Why did SCE develop a credit rating screen that was different than what was stated in Opinion 531?

A. The credit rating screen under Opinion 531 is unnecessarily restrictive, which leads to a proxy group that is too small to produce meaningful ROE results. For SCE, the two-step DCF as prescribed by Opinion 531 results in a proxy group of only 10 companies.

In Opinion 531, the Commission stated, "we find that, in applying the credit rating proxy group screen to exclude companies more than one notch above or below the NETOs' credit ratings, it is appropriate to use both the S&P corporate credit ratings and the Moody's issuer ratings when both are available. <u>If a company is more than one notch above or below the credit ratings of the utilities whose rates are at issue based on either the S&P ratings or the Moody's ratings, that company shall be excluded from the proxy group."</u>[35]

Before Opinion 531, the practice was to exclude companies from the proxy group with corporate credit ratings more than one notch above or below the utility's S&P rating. In this case, SCE, which is rated BBB+ in S&P's scale, would include companies in the proxy group that were ranked A-, BBB+, and BBB.

With the additional Moody's credit rating screen under the direction of Opinion 531, only companies rated Moody's A1, A2, or A3 <u>and</u> S&P's A-, BBB+, or BBB can be included in the proxy group. This results in only 10 companies in the proxy group -- too small to generate a reasonably accurate ROE estimation.

The credit rating screen as dictated in Opinion 531 does not pose as much of an issue for group filers (typically members of an ISO or RTO that file a joint transmission tariff). For group filers, the transmission owners who file jointly typically have credit ratings that are spread across the S&P and Moody's rating scale, so more companies are included in their proxy group. For single filers, the number of companies in the proxy group is necessarily reduced because they only have one S&P and Moody's rating. This effect is more significant when the single-filer utility such as SCE is rated two notches apart, as only companies that satisfy both assigned notches can be included in the proxy group. For example, PECO, which is rated BBB by S&P and A2 by Moody's, has a proxy group of only 3 companies that would satisfy Opinion 531's credit rating screen.[36]

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[35] Opinion 531, P. 52.

[36] Docket ER17-1519, Testimony of Adrien McKenzie, Exhibit PEC-200, Q. 24.

Q. Was there a reason why Opinion 531's credit rating screen excluded companies that were not within the approved notches?

A. The practice of using S&P and Moody's credit ratings in Opinion 531 was originally designed to consider both major credit ratings services because investors rely upon credit ratings from both agencies.[37] The spirit of the ruling was to provide an accurate estimate of a utility's risk based on both credit rating agencies. However, the mechanical application of this rule leads to a proxy group that is too narrow for some utilities. SCE believes that this is an unintended consequence of the ruling as the Commission did not anticipate the credit rating screen could result in such a small proxy group.

Q. What would be the ROE result if SCE followed the mechanical application of the credit rating screen as described in Opinion 531?

A. If SCE performed the credit rating screen strictly according to Opinion 531, the analysis results in a proxy group comprising of only 10 companies. In this case, an ROE set at the median would be 8.06 percent. This is a meaningless ROE result given such a narrow pool of proxy companies. The Commission should not authorize an ROE based on this approach.

Q. Why does an overly small proxy group produce meaningless results?

A. The proxy group serves as a sample to estimate the ROE under the DCF model. Obtaining a sufficient sample size is important because the larger the sample size, the more accurate the results. In the DCF model, the purpose of a proxy group is to estimate the ROE of a utility by comparing it to the ROEs of similar companies. When you have a proxy group that is unreasonably or unnecessarily small, the model produces meaningless ROE results. In an extreme example, the proxy group of San Diego Gas & Electric (SDG&E) would only have one company if the

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[37] Opinion 531, P. 106.

credit rating screen was applied strictly according to Opinion 531. In other words, the estimated ROE of SDG&E under the rules of Opinion 531 would be based solely on Vectren.

Q. What is the solution to the issue of small sample size?

A. Under SCE's expanded two-step DCF model, all investment-grade electric utilities would be included in the proxy group, subject to the other proxy group criteria. This will increase the sample size relative to the Opinion 531 method by including more comparable companies in the proxy group.

Q. Is it reasonable to include all investment-grade electric utilities as part of the credit rating screen?

A. Yes. It is reasonable to include all investment-grade electric utilities because SCE competes with all investment grade companies for equity capital. Opinion 531's S&P and Moody's credit rating screen is based on the rating scales for long-term debt, but we are estimating the return on common equity under the DCF model. Limiting the proxy group within one notch of S&P and Moody's credit rating notches ignores the fact that utilities compete for scarce equity capital with companies from around the nation. Excluding the companies in that group would distort the DCF analysis by unduly limiting the sample.

Q. What are your short-term growth rate assumptions for the expanded two-step DCF model?

A. The expanded two-step DCF model uses IBES as one of the short-term growth rate sources. Other short-term growth rate sources include Bloomberg, Morningstar, S&P Capital IQ, Value Line, and Zacks.

Q. How does this differ from the Opinion 531 two-step DCF model?

A. The Opinion 531 two-step DCF model only uses IBES as a source for the short-term growth rate.

Q. Why do you use sources other than IBES for short-term growth rates?

A. Investors have a wide range of expectations for the market and IBES alone is not necessarily representative of their different prospects of utility common stocks. While IBES can be used as one source to estimate investors' expectations, Bloomberg, Morningstar, S&P Capital IQ, Value Line, and Zacks are other credit sources that can be use to reflect the diverse range of investors' expectations. It reduces the subjectivity of using only one source for the short-term growth rate. In Opinion 531, the Commission reaffirmed that "there may be more than one valid source of growth rate estimates."[38]

Q. How does using other sources of short-term growth rates improve the zone of reasonableness?

A. Using additional sources for short-term growth rate makes the zone of reasonableness more robust by increasing relevant data points that reflect the full range of investors' return expectation. Using growth rate projections from multiple sources increases the sample size, which makes the range of estimated ROEs more reliable.

Q. What are your long-term growth rate assumptions for the expanded two-step DCF model?

A. The long-term growth rate for the expanded two-step DCF model is based on the long-term projections of nominal GDP published by IHS Global Insight, Energy Information Administration (EIA), and the Social Security Administration (SSA).

Q. Please explain how you weighted the short-term and long-term growth rate for the expanded two-step DCF model.

A. The weighting of the short-term and long-term growth rate is consistent with Opinion 531. The short-term growth rates are weighted two-thirds and the GDP growth rate is weighted one-third to compute the growth rates for each company in the proxy group.

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38 Opinion 531 at P. 90.

Q. How did you calculate the dividend yield (D/P) in the expanded two-step DCF analyses?

A. The dividend yield calculations for the expanded two-step DCF model is consistent with Opinion 531. It is based on financial data for the six-month period ending July 2017 under the three-step process as described by Opinion 531: "(1) averaging the high and low stock prices as reported by the New York Stock Exchange or NASDAQ for each of the six months in the study period; (2) dividing the company's indicated annual dividend for each of those months by its average stock price for each month (resulting in a monthly dividend yield for each month of the study period); and (3) averaging those monthly dividend yields."[39]

Q. Did you eliminate any low-end results that are unreasonably low?

A. Yes, I eliminated the following ROE estimates:

39 Opinion 531, P. 38.

ROE Estimates	**IBES**	**Value Line**	**Bloomberg**	**Morningstar**	**S&P Capital IQ**	**Zacks**
Avista		5.50%				
Entergy	1.54%	1.73%	3.36%	3.10%		6.20%
Exelon	5.93%					
FirstEnergy	3.27%		4.78%			5.89%
Hawaiian Electric		3.35%		6.75%		
IDACORP	6.75%	6.62%				
MGE Energy	6.03%					
Northwestern			6.02%	5.74%	6.02%	6.02%
Pacific Gas & Electric				5.88%		
Portland General					6.58%	6.62%
PPL		5.39%		5.86%		
Public Service Enterprise	5.00%					

In previous decisions, the Commission has recognized that DCF estimates that are too close to current utility bond yields are unreasonable. In Opinion 531, the Commission stated, "the purpose of the low-end outlier test is to exclude from the proxy group those companies whose ROE estimates are below the average bond yield or are above the average bond yield but are sufficiently low that an investor would consider the stock to yield essentially the same return as debt."[40] In public utility cases, the common practice was to set the low-end threshold 100 basis points above the utility bond yield, but the Commission has acknowledged that a flexible application is appropriate. Opinion 531 stated, "In public utility ROE cases, the Commission has used 100 basis points above the cost of debt as an approximation of this threshold, but has also considered the distribution of proxy group companies to inform its decision on which companies are outliers. As the Presiding Judge explained, this is a flexible test."[41]

The simplistic practice of setting the low-end threshold 100 basis points above the utility bond yield does not contemplate that the spread between utility bond yields and the cost of utility equity can change over time and the 100 basis point threshold may be too low.

In order to reflect current market conditions, we estimate the low-end threshold using the following method. The low-end threshold can be estimated by using the risk premium formula, by using the CAPM to calculate the difference between the rate of return on utility equity and the rate of return on bonds.

(1) $$r_{UTILITY} = r_f + \beta_{UTILITY}(r_m - r_f) = r_f + \beta_{UTILITY} * MRP$$

(2) $$r_{BONDS} = r_f + \beta_{BONDS}(r_m - r_f) = r_f + \beta_{BONDS} * MRP$$

Subtracting equation (1) and equation (2) leads to equation (3) below:

(3) $$r_{UTILITY} - r_{BONDS} = (\beta_{UTILITY} - \beta_{BONDS}) * MRP$$

By using a 0.26 beta for corporate bonds[42], 0.50 beta for a low-end utility equity

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[40] Opinion 531 at P. 122.

[41] *Ibid.*

[42] Elton, E. J., M. J. Gruber, D. Agrawal, and C. Mann, "Explaining the Rate Spread on Corporate Bonds," The Journal of Finance, February 2001, p. 270, fn. 32.

return[43], and 9.62% for the market risk premium, the low-end threshold is estimated to be 231 basis points above the Baa utility bond yield. *See* equation 4 below.

(4)

$$r_{UTILITY} - r_{BONDS} = (\beta_{UTILITY} - \beta_{BONDS}) * MRP = (0.5 - 0.26) * 0.0962 = 0.0231 = 2.31\%$$

Q. How does the expanded two-step DCF model's method of eliminating low-end unreasonable results improve the zone of reasonableness?

A. It ensures that the zone of reasonableness does not include ROE estimates that are too close to the cost of debt to be reasonable.

Q. What is the estimated zone of reasonableness?

A. The expanded two-step DCF model produces a zone of reasonableness range from 6.41% to 15.64%.

Q. Did you eliminate any unreasonable high-end results?

A. Yes, I eliminated the ROE estimate of 26.23% for American Electric Power in the DCF model using Morningstar growth rate as the short-term growth rate. The purpose of eliminating certain high-end results is to exclude companies whose growth rates are unsustainably high. Under Opinion 531, it is no longer necessary to remove high-end results because the two-step DCF methodology assumes that the long-term growth rate for each company is equal to the GDP growth rate. However, in my judgment, this two-step growth rate for American Electric Power (when the Morningstar growth rate of 31.20% is the short-term growth rate) is unreasonably high when compared with the other two-step growth rates for AEP.

Q. Please summarize your DCF results.

A. As shown in Exhibit No. SCE-18, my DCF analysis estimates SCE's cost of

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43 The beta of 0.50 for utility equity is based on the lowest beta from the all investment grade proxy group.

common equity to be between 6.41 percent and 15.64 percent, with the half way point between the median of the zone of reasonableness and the top of the zone of reasonableness estimate of 12.08 percent (*see* p. 2 of 15).

My DCF analysis, with low and high estimates of ROE of 6.41 percent and 15.64 percent, respectively, defines an accepted reasonable range of ROE for SCE.[44] SCE's proposed ROE, including ROE adders for specific projects as discussed above, falls comfortably within the zone of reasonableness.

Q. What is your conclusion regarding the appropriate base ROE for SCE?

A. Based on the above discussion, and the analysis presented in the sections that follow, a base ROE of 10.30 percent is appropriate for SCE. In the final section of my testimony, I explain why, in light of the totality of the evidence, a 10.30% base ROE is just and reasonable and should be adopted.

VIII. ESTIMATES OF RETURN ON EQUITY BASED ON THE OPINION 531 TWO-STEP DCF MODEL

Q. Have you prepared a DCF analysis based using the methodology set forth in Opinion 531?

A. Yes. Although I believe that in this case certain refinements are needed to this method, as discussed above, I have prepared such an analysis in order to inform the Commission of the results of that model. I do not recommend basing SCE's ROE on the results of this analysis.

Q. How did you select the proxy group for the Opinion 531 two-step DCF model?

A. The Opinion 531 two-step DCF model input assumptions that I used are consistent with the method prescribed in Opinion 531. The proxy group is selected as follows:

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[44] Opinion 445 at 61,265-61,266.

- Companies categorized as electric utilities by Value Line Investment Survey.
- Electric utilities that are within one notch of the SCE's credit rating from S&P and Moody's, when both are available.[45]
- Companies currently paying a common stock dividend and dividend payments are expected to continue.
- Companies not involved in major merger activity or major restructuring during the period of analysis that distorts the DCF inputs.

Q. How did you calculate the dividend yield (D/P) in your Opinion 531 two-step DCF analyses?

A. The dividend yield calculations for the Opinion 531 two-step DCF model is consistent with the Commission's order. It is based on financial data for the six-month period ending July 2017 under the three-step process as described by Opinion 531: "(1) averaging the high and low stock prices as reported by the New York Stock Exchange or NASDAQ for each of the six months in the study period; (2) dividing the company's indicated annual dividend for each of those months by its average stock price for each month (resulting in a monthly dividend yield for each month of the study period); and (3) averaging those monthly dividend yields."[46]

Q. Please explain how you calculated the growth rate (*g*).

A. The calculated growth rate is consistent with the directions under Opinion 531. The short term growth rate is based on the five-year Institutional Brokers' Estimate System (IBES) growth rate projections from *Yahoo! Finance*. The long term growth rate is based on Gross Domestic Product (GDP) projections published by HIS Global Insight, the U.S. Energy Information Administration (EIA), and the

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45 When only one rating is available, that rating is sufficient to include or exclude the company.

46 Opinion 531, P. 38.

Social Security Administration (SSA).

The weighting of the short-term and long-term growth rate is also consistent with Opinion 531. The IBES short-term growth rate are weighted two-thirds and the GDP growth rate is weighted one-third to compute a single two-step growth rate for each company in the proxy group.

Q. Did you eliminate any high-end results?

A. No, I did not eliminate any high-end results, which is consistent with Opinion 531. The purpose of eliminating high-end results is to exclude companies whose growth rates are unsustainably high. Under Commission's opinion, this is not an issue anymore because the two-step DCF methodology assumes that the long-term growth rate for each company is equal to the GDP.

Q. Did you eliminate any unreasonable low-end results?

A. No. Consistent with Commission practice in Opinion 531, I would only eliminate companies with estimated ROEs that are below 100 basis points above the utility bond yields, as measured by Moody's over the period from February 2017 to July 2017. Because all of the companies in the proxy group have estimated ROEs 100 basis points above the utility bond yield, I did not eliminate any low-end results.

Q. What are the ROE estimates based on the Opinion 531 two-step DCF model?

A. Based on Opinion 531's two-step DCF model, the cost of equity estimates range from 6.97 percent to 9.16 percent with a median of 8.06 percent. The half way between the median and the top of the zone of reasonableness is 8.61 percent.

As discussed above, the mechanical application of Opinion 531's two-step DCF model result in a zone of reasonableness that is unjust and unreasonable because it is too low to satisfy the standards of *Hope* and *Bluefield*. Also, SCE's proxy group using the Opinion 531 methodology only contain 10 companies, a sample size that is too small to produce meaningful results. I am presenting the results of the two-step DCF model only as a point of reference.

IX. OTHER ROE BENCHMARKS AND SUPPORTING STUDIES

Q. What is the purpose of this section of the testimony?

A. The purpose of this section of the testimony is to provide alternative ROE benchmarks and studies to support my recommended ROE. While the DCF methodology has been the Commission's choice in estimating the ROE, it is not the only approach. There are other widely accepted methods and I have included them in this section to test the reasonableness of the expanded two-step DCF results. These methods include the comparable earnings model, Capital Asset Pricing Model (CAPM), and the empirical Capital Asset Pricing Model.

Q. Please describe your application of the risk premium approach.

A. The risk premium method of determining ROE is based on an estimate of the additional return necessary to induce investors to purchase an asset with greater risk (*e.g.*, a utility common stock) than a lower risk asset (*e.g.*, a long-term utility bond) or a risk-free asset (*e.g.*, a long-term Treasury bond). This additional return component is added to the current yield on bonds in order to estimate the cost of equity. Like the DCF model, risk premium analyses are capital market oriented; but unlike methods where the cost of equity is indirectly impacted by risk factors, risk premium methods estimate investors' required rates of return directly by adding a risk premium to observable bond yields. This relationship can be expressed as follows:

ROE = R + RP where

ROE = investors' required return on common equity

R = current yield on the risk-free or low-risk asset

RP = risk premium on electric utility common equity

SCE has applied two risk premium methods in the following sections, the Capital Asset Pricing Model, and the Empirical Capital Asset Pricing Model.

Q. Please describe your application of the CAPM approach.

A. The CAPM was first introduced in the 1960s by Sharpe, Lintner, and Treynor.[47] The CAPM is a single-factor approach to explain systematic differences in asset returns. The CAPM calculates the return on common equity as the sum of the risk-free rate (or the return on the risk-free asset, usually taken to be Treasury bills or Treasury bonds) and the company-specific risk measure, beta, multiplied by an expected market risk premium. The expected market risk premium, in turn, is equal to the difference between the expected return on the market portfolio and the risk-free rate. (Here, "market" means the composite of all stocks that could be held by an investor.) Mathematically, this is written as:

$$r = r_f + \beta(r_m - r_f) = r_f + \beta * MRP$$

where

r = investors' required return on common equity

r_f = the risk-free rate

β = the company-specific risk measure

MRP = the market risk premium, which is the expected difference between the return on the market portfolio and the risk-free rate.

As presented in Exhibit SCE-20, the cost of equity has a range of 7.68

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47 A good basic discussion of the CAPM is found in R. A. Brealey and S. C. Myers, *Principles of Corporate Finance*, 5th ed. (New York: The McGraw-Hill Companies, Inc., 1996), pp. 173-203. A more technical discussion is found in T. E. Copeland and J. F. Weston, *Financial Theory and Corporate Policy* (Reading, Massachusetts: Addison-Wesley Publishing Company, 1979), pp. 160-196. Seminal articles include W. F. Sharpe, "Capital Asset Prices: A Theory of Market Equilibrium Under Conditions of Risk," *Journal of Finance*, Vol. 19 (September 1964), pp. 425-442; J. Lintner, "The Valuation of Risk Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets," *Review of Economics and Statistics*, Vol. 47 (February 1965), pp.13-37; Treynor's article was not published.

percent to 12.89 percent with a midpoint of 10.29 percent and a median of 9.61 percent.

Q. Please explain how Beta is calculated.

A. Beta, the company-specific risk measure, measures the sensitivity of the company's return to the market return. Mathematically, for security i, beta is defined as:

$$\beta_i = \frac{\sigma_{im}}{\sigma_m^2}$$

where σ_{im} is the covariance between security i's return and the market return, and σ_m^2 is the variance of the market return.

The observed beta for a firm's stock reflects both business risk and financial risk. Business risk is the risk associated with a firm's line of business. It includes all of the factors that affect the likelihood that investors will realize expected gains, such as the extent of competition, economic and market conditions, regulation, and other government intervention. Financial risk arises from the extent to which the firm is financed by the issuance of debt. The more debt a firm issues (strictly, the higher the ratio of debt in the firm's capital structure), the more financial risk that is borne by the holders of the firm's equity.

In order to correctly use the CAPM to calculate the return on common equity for SCE, the observed betas of the firms in the comparable group must first be unlevered (removing the financial risk effect that is measured by the firm's debt/equity ratio) to isolate the beta corresponding to each firm's business risk. This business risk beta is then re-levered at SCE's debt/equity ratio to properly calculate the beta that should be used to estimate SCE's cost of equity. The basic formula is:

$$\beta_{levered} = [1 + (1-t)\frac{D}{E}]\beta_{unlevered}$$

where *t* is the corporate tax rate. In this analysis, the corporate tax rate is assumed to be 0.4.

Q. How did you calculate the market risk premium?

A. I calculated the forward looking market risk premium by adding a forecast of the dividend yield to a forecast of the growth rate of earnings per share (EPS) based on forward looking data on the S&P 500 Index obtained from Bloomberg and as applied to the all investment grade electric utilities proxy group. These calculations are presented in Exhibit No. SCE-20. With a dividend yield and growth rate in EPS[48] of 2.04 percent and 11.06 percent, respectively, the return on the market is 13.33 percent. Subtracting a risk free rate of 3.71 percent based on a September 2017 estimate of the yield on 30-Year Treasury bonds produces a market risk premium of 9.62 percent.

I performed an additional analysis supporting my forward looking market risk premium by estimating the ROE of the individual companies in the S&P 500. The calculation is similar to the DCF method, where I estimated the ROE by adding the dividend yield (adjusted for growth) and forecasted growth rate of each individual company. Different forms of the analysis produced ROEs ranging from 9.27% to 10.74%, which serve as benchmarks for the market risk premium I presented above. Details of the analysis are presented in Exhibit No. SCE-20.

Q. Please describe your application of the eCAPM approach.

A. It is well known that the CAPM under-predicts equity returns for companies with betas that are less than one, and over-predicts returns for companies with betas that are greater than one. This observation has resulted in the "empirical CAPM," which incorporates a modification that reflects this behavior in equity returns. The

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[48] Bloomberg provides three forecasts of EPS growth rates: 12 month forward looking, one calendar year forecast, and two year calendar forecast. For example, in September 2017, the 12 month forward looking forecast will be for September 2018, the one calendar year forecast will be for December 2018, and the two year calendar forecast will be for December 2019. SCE used these data to calculate monthly growth rates for the period December 2017 to December 2019 and then annualized these monthly growth rates. Refer to Exhibit SCE-20.

empirical CAPM is implemented by an adjustment to the standard CAPM equation that results in the following form:[49]

$$r = r_f + 0.25(r_m - r_f) + 0.75[\beta(r_m - r_f)]$$

The addition of the 0.75 and 0.25 weights reduces the slope of the CAPM's security market line (from $r_m - r_f$ to $0.75(r_m - r_f)$) and raises the intercept (from r_f to $r_f + 0.25(r_m - r_f)$). The result is that for betas less than one, this has the effect of raising the return on equity, and for betas greater than one, this has the effect of decreasing the return on equity.

As presented in Exhibit No. SCE-20, the cost of equity has a range of 9.09 percent to 13.00 percent with a midpoint of 11.05 percent and a median of 10.54 percent.

Q. What are your sources for Beta?

A. SCE used company-specific betas taken from the Value Line Investment Survey. Value Line Investment Survey is a respected source of information for investors.

Q. Please provide a summary of results for CAPM.

A.

ROE Estimates	Min	Midpoint	Median	Max
CAPM	7.68%	10.29%	9.61%	12.89%
eCAPM	9.09%	11.05%	10.54%	13.00%

Q. Please describe your application of the comparable earnings model.

A. The comparable earnings model estimates the ROE by evaluating book returns on equity for unregulated companies of comparable risk. The rationale is consistent with the fair return standard as described in the *Hope* case, "the return to the equity owner should be commensurate with returns on investments in other

49 Roger A. Morin, "New Regulatory Finance," Public Utilities Reports at 189 (2006).

enterprises having corresponding risks."[50]

The intention of my comparable earnings model is to provide a benchmark of the fair return on equity for regulated utilities. Regulation is supposed to duplicate the results under a competitive and unregulated environment. By evaluating the ROEs of comparable and unregulated companies over a full business cycle of ten years, and using a conversion factor to adjust the risk differential between regulated and unregulated companies, the comparable earnings model estimates a benchmark ROE for SCE. Details of the calculations are presented in Exhibit No. SCE-19.

In identifying a group of comparable unregulated companies for the proxy group, I start with the companies in the S&P 500 index. The proxy group is formed by the following criteria:

- Exclude financial institutions, *i.e.*, banks, investment companies and real estate companies, etc., because of their very high degree of financial leverage and capital turnover;
- Exclude utilities in the unregulated proxy group to avoid circular reference;
- Include low volatility company with beta between 0 to 0.95;
- Exclude companies with any missing data during the ten year study period;
- Exclude companies involved in merger and acquisition activities and if the addition accounts for 5% or more of the acquirer's asset portfolio.

As a result, there are a total of 84 companies in the unregulated proxy group. For each company in the proxy group, I obtained the Value Line projected ROE for 2017 to 2022 and averaged the results. This resulted in an average of 35.14% ROE for the unregulated proxy group. This number needs to be adjusted

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50 Hope Natural Gas, 320 U.S. at 603.

to reflect the risk differential between regulated companies and unregulated companies. Regulated companies do not face the same level of competition as unregulated companies do, so a conversion factor is needed.

The conversion factor calculates the ratio ROEs for regulated electric utilities to ROEs for the unregulated companies in the proxy group. This ratio provides the conversion factor needed to adjust the future projected ROE for unregulated companies.

Let ROE = Return on Equity, M/B = Market-to-Book Ratio, P/E = Price/Earnings Ratio, B = book value of equity per share, E = earnings per share, P = stock price. The subscript of "r" is for regulated and "u" for unregulated:

- ROE = E / B
- Market-to-book ratio = P/B
- Price-to-earnings ratio = P / E

Because

$\frac{E}{B} = \frac{P/B}{P/E} = ROE = \frac{(M/B)}{(P/E)}$, the conversion factor is

$$\frac{ROE_R}{ROE_U} = \frac{(M/B)_R /(P/E)_R}{(M/B)_U /(P/E)_U} = \frac{(M/B)_R}{(P/E)_R} * \frac{(P/E)_U}{(M/B)_U} = \frac{(M/B)_R}{(M/B)_U} * \frac{(P/E)_U}{(P/E)_R}$$

To obtain the market-to-book and price-to-earnings ratio benchmarks, I retrieved the data on Value Line, calculated the median for the unregulated proxy group as derived above for the unregulated ratios, and my regulated proxy group (33 companies) for the regulated ratios. I calculated the median from the period between 2007-2016 in order to reflect the earnings of a full business cycle and eliminate any short-term fluctuations.

The conversion factor is calculated as follows:

$$\frac{ROE_R}{ROE_U} = \frac{(M/B)_R}{(M/B)_U} * \frac{(P/E)_U}{(P/E)_R} = \frac{1.52}{3.55} * \frac{17.30}{15.60} = 47.34\%$$

Applying the conversion factor to the projected unregulated ROE results in the ROE estimate for SCE:

Estimated ROE = Unregulated ROE Project * Risk Conversion Factor

Estimated ROE = 35.14% * 47.34% = 16.64%

X. ANOMALOUS CAPITAL MARKET CONDITIONS

Q. What is the purpose of this section of your testimony?

A. The purpose of this section of the testimony is to demonstrate how the current economic environment has not returned to normal conditions since the recession that started in 2008. As a result, the current anomalous capital market conditions do not provide a representative landscape in which to determine a fair ROE under the two-step DCF method.

Q. What do you mean by anomalous capital market conditions?

A. Since the 2008 recession, the Federal Reserve has purchased enormous amounts of debt securities in order depress market interest rates and stimulate the economy. The objective of this monetary policy is to increase employment and maintain market stability.[51] The Fed's unprecedented purchases of Treasury bonds and other financial instruments have artificially suppressed interest rates below the levels that would otherwise prevail in the market. While the Federal Reserve has raised the Federal Funds rate slowly in the last two years, increases have been small and current interest rates are nowhere near pre-recession levels.

In addition, increased uncertainty in the capital markets have caused

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[51] https://www.federalreserve.gov/aboutthefed/files/pf_3.pdf, P. 21, "It is the Federal Reserve's actions, as a central bank, to achieve three goals specified by Congress: maximum employment, stable prices, and moderate long-term interest rates in the United States

investors to flock to safer investments. With turmoil in the international financial system, such as the risk of several EU countries defaulting on their debt and the United Kingdom (UK) leaving the European Union (EU), the increase in the demand for U.S. Treasuries and other U.S. financial instruments continues to keep interest rates low.

These conditions are temporary and are not necessarily representative of what investors expect in the future. As the U.S. labor market continues to improve and real consumption starts to rise, the Federal Reserve has indicated that the federal funds rate will be adjusted when economic conditions stabilize.[52] Federal Reserve Chair Janet Yellen stated recently, "we anticipate reducing reserve balances and our overall balance sheet to levels appreciably below those seen in recent years but larger than before the financial crisis."[53] The Fed's plan to slowly reduce the size of its balance sheet by decreasing its reinvestment rate indicates that financial markets will return to normal gradually. The Federal Reserve's assets currently total approximately $4.5 trillion. At the reductions projected in a recent Chair Yellen's speech, the assets will decline to $4.4 trillion by October 2018 and $4.2 trillion by October 2019.[54] This slow decline means that anomalous conditions will continue to persist.

Q. Is there other evidence that the Commission should consider in evaluating anomalous capital market conditions?

A. Yes. The Commission should consider the behavior of real interest rates before and after the Great Recession.

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52 Transcript of Chair Yellen's Press Conference, June 14, 2017, https://www.federalreserve.gov/mediacenter/files/FOMCpresconf20170614.pdf

53 *Ibid.*, P. 5.

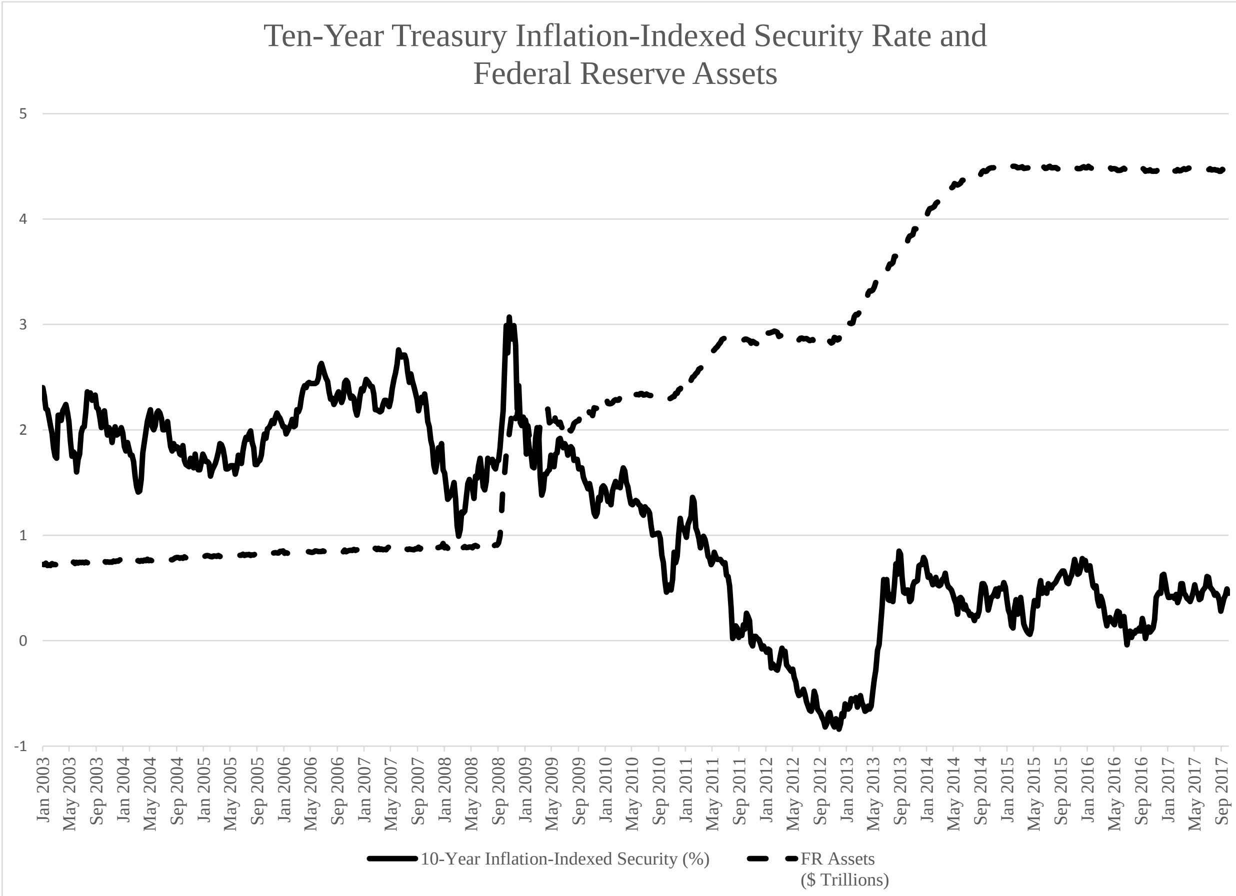
54 Transcript of Chair Yellen's Opening Statement to the Media, September 20, 2017, https://www.cnbc.com/2017/09/20/heres-the-full-transcript-of-janet-yellens-media-brief.html

Q. Please explain what a real interest rate is and what it shows.

A. Interest rates that we observe in financial markets are nominal interest rates. They can be decomposed into a real component and an inflation component. This is similar to the difference between nominal gross domestic product (GDP) and real gross domestic product. Real GDP gives a true measure of variations in economic activity, whereas changes in nominal GDP can be the result of changes in prices without any change in output. Likewise, real interest rates show how much of a loan payment represents a transfer of purchasing power from the borrower to the lender.

The chart immediately below is a graph of the real interest rate, represented by the rate on the ten-year Treasury inflation-indexed security (in percent) and the level of Federal Reserve assets (in trillions of dollars).

The important periods in the chart are (1) from January 2003 through August 2008, immediately before the Lehman Brothers bankruptcy in September 2008 and (2) from June 2013 until the present. Over the first period, the real interest rate averaged 1.99 percent, while over the second period, the real interest rate averaged 0.41 percent. The consistently lower rate during the second period shows that anomalous capital market conditions continue.



Q. Can you please elaborate how turmoil in the international financial system can affect U.S. Treasury rates?

A. Fears about the European economic situation have likely sent investors flocking to U.S. Treasuries for less risky returns. Some EU countries such as Greece, Spain, Portugal, and Ireland have high amounts of debt relative to their GDPs, which can lead to default and the possibility of these countries exiting the Eurozone. In addition, with the UK opting to exit the EU ("Brexit"), the two year negotiation process for the exit deal will cause uncertainty in the financial markets. The European debt crisis and Brexit may lead to investors demanding safer investments in the United States. This demand will lower U.S. interest rates.

Q. Did the Commission acknowledge how anomalous capital market conditions affect its determination of the authorized ROE?

A. Yes. In both Opinion 531 and Opinion 551, the Commission acknowledged the presence of anomalous capital market conditions, which causes concern that a mechanical application of the two-step DCF methodology would result in a return that does not correspond with *Hope* and *Bluefield* standards. Specifically, Opinion 551 stated, "Because the evidence in this proceeding indicates that capital markets continue to reflect the type of unusual conditions that the Commission identified in Opinion No. 531, we remain concerned that a mechanical application of the DCF methodology would result in a return inconsistent with Hope and Bluefield…. We therefore find it necessary and reasonable to consider additional record evidence, including evidence of alternative methodologies and state-commission approved ROE."[55]

XI. SELECTION OF AN ROE WITHIN THE ZONE OF REASONABLENESS

Q. How did the Commission select an ROE within the zone of reasonableness?

A. As discussed in Section V, prior to Opinion 531, the Commission generally selected a base ROE using the median ROE for single utility filers. In Opinion 531, the Commission found that a base ROE set at the middle of the zone was unjust and unreasonable due to anomalous capital market conditions[56] and in view of the results of alternative benchmark analyses. In order to determine a just and reasonable ROE, the Commission authorized the base ROE set at the midpoint of the upper middle half of the zone of reasonableness.

Q. Please explain how SCE's base ROE request of 10.30% relate to the Commission's approach.

A. When the U.S. Court of Appeals for the D.C. Circuit vacated and remanded Opinion 531 in April 2017, the court found that the Commission did not

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[55] Opinion 551, P. 122.

[56] Opinion 531, P. 41 and P. 145.

adequately explain the placement of the ROE at the midpoint of the upper half of the zone of reasonableness. Taking the remand into consideration, I developed multiple financial models, including the expanded two-step DCF model, CAPM, eCAPM, and comparable earnings to support our ROE request. The base ROE request of 10.30% falls comfortably within the range of these financial models.

In addition, as explained in Section IV above, 10.30% is the ROE that the CPUC has authorized for 2018 and 2019,[57] and the Commission has consistently found that provision of transmission service is riskier than distribution. Along with the evidence that I presented in Section IV regarding the risky environment that California faces with the influx of DERs and ambitious renewable goals, an appropriate return on transmission investments is necessary to ensure that investors are adequately compensated.

Q. What are your final conclusions?

A. My final conclusions are that SCE's requested 10.30 percent base ROE is reasonable. In addition, the expanded two-step DCF estimates define a zone of reasonableness that encompasses the Commission-approved adder for SCE's membership in the CAISO of 0.50 percent, and the 0.75 percent, 1.25 percent and 1.00 percent ROEs for specific projects, as discussed above, that are included in the formula rate calculations.

Q. Does this conclude your testimony?

A. Yes, it does.

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[57] 2019 ROE is subject to the trigger of the cost of capital mechanism. The mechanism is based on an interest rate benchmark. Current projections show that an upward trigger is possible, but unlikely. An upward trigger would result in a higher ROE. For details, please refer to D.17-07-005, P. 4.

<u>AFFIDAVIT of AUTHENTICATION</u>

State of California)

) ss

County of Los Angeles)

Dr. Paul T. Hunt, being first duly sworn, on oath says that he is identified in the foregoing prepared direct testimony; that the answers therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Paul T. Hunt

Paul T. Hunt

A notary public or other officer completing this certificate verifies only the identity of the individual who signed the document to which this certificate is attached, and not the truthfulness, accuracy, or validity of that document.

Subscribed and sworn to (or affirmed) before me on this 24th day of October, 2017 by Paul T. Hunt, JR., proved to me on the basis of satisfactory evidence to be the person(s) who appeared before me.

Karrie A. Ridenour

Notary Public

KARRIE A. RIDENOUR
Notary Public - California
Los Angeles County
Commission # 2180448
My Comm. Expires Jan 20, 2021

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

<u>EXHIBIT SCE-18</u>

EXHIBIT TO THE TESTIMONY OF
DR. PAUL T. HUNT

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Estimated ROEs for Expanded Two-Step DCF

Line No.		Company	IBES	Value Line	Bloomberg	Morningstar	S&P Capital IQ	Zacks	Bond Yield Threshold (Moody's Rate plus 231 Basis Points)	IBES	Value Line	Bloomberg	Morningstar	S&P Capital IQ	Zacks	Overall
			Estimated ROEs (Before Screening Against Bond Yield)							**Estimated ROEs (Adjusted Range, Screened Against Bond Yield)**						
1.	ALE	Allete Inc	7.91%	7.88%	9.41%	9.41%	9.41%	8.66%	6.79%	7.91%	7.88%	9.41%	9.41%	9.41%	8.66%	
2.	LNT	Alliant Energy Corp	8.98%	10.50%	8.44%	8.34%	8.68%	8.34%	6.41%	8.98%	10.50%	8.44%	8.34%	8.68%	8.34%	
3.	AEE	Ameren Corp	8.76%	8.37%	8.45%	8.45%	8.72%	9.06%	6.79%	8.76%	8.37%	8.45%	8.45%	8.72%	9.06%	
4.	AEP	American Electric Power Company Inc	6.52%	6.49%	6.60%		8.65%	8.58%	6.41%	6.52%	6.49%	6.60%		8.65%	8.58%	
5.	AGR	AVANGRID Inc.	11.57%	10.05%	11.57%		11.57%	11.23%	6.79%	11.57%	10.05%	11.57%		11.57%	11.23%	
6.	AVA	Avista Corp	8.73%	5.50%		8.50%			6.79%	8.73%			8.50%			
7.	BKH	Black Hills Corp	12.23%	10.93%	8.50%	7.48%	7.48%	7.48%	6.79%	12.23%	10.93%	8.50%	7.48%	7.48%	7.48%	
8.	CNP	CenterPoint Energy Inc	9.33%	12.52%	9.77%	10.85%	9.79%	8.24%	6.41%	9.33%	12.52%	9.77%	10.85%	9.79%	8.24%	
9.	CMS	CMS Energy Corp	9.47%	8.98%	9.41%	9.32%	9.29%	9.12%	6.79%	9.47%	8.98%	9.41%	9.32%	9.29%	9.12%	
10.	ED	Consolidated Edison Inc	7.63%	6.75%	7.98%	7.50%	7.29%	7.30%	6.41%	7.63%	6.75%	7.98%	7.50%	7.29%	7.30%	
11.	D	Dominion Energy	7.66%	9.07%	9.02%	9.95%	9.40%	9.40%	6.79%	7.66%	9.07%	9.02%	9.95%	9.40%	9.40%	
12.	DTE	DTE Energy Company	7.73%	9.32%	8.24%	7.80%	8.62%	8.62%	6.79%	7.73%	9.32%	8.24%	7.80%	8.62%	8.62%	
13.	DUK	Duke Energy Corp New	7.32%	11.18%	8.83%	11.80%	8.24%	8.30%	6.41%	7.32%	11.18%	8.83%	11.80%	8.24%	8.30%	
14.	EIX	Edison International	6.97%	8.20%	8.41%	8.87%	7.58%	8.73%	6.79%	6.97%	8.20%	8.41%	8.87%	7.58%	8.73%	
15.	EE	El Paso Electric Co	8.35%	7.10%	8.35%	7.88%	9.06%	9.10%	6.79%	8.35%	7.10%	8.35%	7.88%	9.06%	9.10%	
16.	ETR	Entergy Corp	1.54%	1.73%	3.36%	3.10%	10.82%	6.20%	6.79%					10.82%		
17.	ES	Eversource Energy	8.47%	8.85%	8.75%	8.77%	8.71%	8.71%	6.41%	8.47%	8.85%	8.75%	8.77%	8.71%	8.71%	
18.	EXC	Exelon Corp	5.93%	13.66%	7.35%	7.05%	8.49%	8.49%	6.79%		13.66%	7.35%	7.05%	8.49%	8.49%	
19.	FE	FirstEnergy Corp	3.27%	9.99%	4.78%	8.10%	7.54%	5.89%	6.79%		9.99%		8.10%	7.54%		
20.	FTS	Fortis Inc	9.86%	12.91%	9.68%		9.68%	10.03%	6.41%	9.86%	12.91%	9.68%		9.68%	10.03%	
21.	HE	Hawaiian Electric Industries Inc	7.03%	3.35%	7.34%	6.75%	8.02%	7.92%	6.79%	7.03%		7.34%		8.02%	7.92%	
22.	IDA	IDACORP Inc	6.75%	6.62%	7.43%	7.43%	7.43%	7.09%	6.79%			7.43%	7.43%	7.43%	7.09%	
23.	MGEE	MGE Energy Inc	6.03%	8.95%					6.23%		8.95%					
24.	NWE	NorthWestern Corporation	6.99%	7.22%	6.02%	5.74%	6.02%	6.02%	6.79%	6.99%	7.22%					
25.	OGE	OGE Energy Corp	9.16%	10.42%	9.91%	9.91%	8.95%	8.48%	6.41%	9.16%	10.42%	9.91%	9.91%	8.95%	8.48%	
26.	OTTR	Otter Tail Corp	8.26%	9.86%	9.19%	8.95%			6.79%	8.26%	9.86%	9.19%	8.95%			
27.	PCG	Pacific Gas and Electric Company	7.32%	11.08%	6.97%	5.88%	7.08%	7.86%	6.41%	7.32%	11.08%	6.97%		7.08%	7.86%	
28.	PNW	Pinnacle West Capital Corp	8.68%	8.53%	8.52%	8.97%	8.52%	8.08%	6.41%	8.68%	8.53%	8.52%	8.97%	8.52%	8.08%	
29.	PNM	PNM Resources Inc	9.01%	9.91%	8.16%	7.55%	7.82%	7.21%	6.79%	9.01%	9.91%	8.16%	7.55%	7.82%	7.21%	
30.	POR	Portland General Electric Company	8.08%	8.93%	6.92%	6.89%	6.58%	6.62%	6.79%	8.08%	8.93%	6.92%	6.89%			
31.	PPL	PPL Corporation	6.42%	5.39%	6.41%	5.86%	9.36%	9.02%	6.41%	6.42%		6.41%		9.36%	9.02%	
32.	PEG	Public Service Enterprise Group Inc	5.00%	8.25%	7.47%	7.88%	7.33%	6.92%	6.79%		8.25%	7.47%	7.88%	7.33%	6.92%	
33.	SCG	SCANA Corporation	9.16%	7.62%	7.83%	8.20%	8.30%	8.27%	6.79%	9.16%	7.62%	7.83%	8.20%	8.30%	8.27%	
34.	SRE	Sempra Energy	10.70%	12.56%	11.60%	15.64%	10.63%	10.26%	6.79%	10.70%	12.56%	11.60%	15.64%	10.63%	10.26%	
35.	SO	Southern Co	8.19%	9.03%	9.32%	9.14%	9.48%	9.00%	6.41%	8.19%	9.03%	9.32%	9.14%	9.48%	9.00%	
36.	VVC	Vectren Corp	8.04%	8.12%	8.04%		8.38%	8.18%	6.41%	8.04%	8.12%	8.04%		8.38%	8.18%	
37.	WEC	WEC Energy Group	8.68%	8.16%	8.64%	9.01%	8.43%	8.60%	6.41%	8.68%	8.16%	8.64%	9.01%	8.43%	8.60%	
38.	XEL	Xcel Energy Inc	8.22%	7.64%	8.48%	8.75%	8.39%	8.27%	6.41%	8.22%	7.64%	8.48%	8.75%	8.39%	8.27%	
11.		**Adjusted Range, Low Value**								**6.42%**	**6.49%**	**6.41%**	**6.89%**	**7.08%**	**6.92%**	**6.41%**
12.		**Adjusted Range, High Value**								**12.23%**	**13.66%**	**11.60%**	**15.64%**	**11.57%**	**11.23%**	**15.64%**
13.		**Midpoint of Adjusted Range**								**9.32%**	**10.07%**	**9.00%**	**11.27%**	**9.32%**	**9.07%**	**11.02%**
14.		**75th Percentile, Midpoint of Adjusted Range**								**10.78%**	**11.86%**	**10.30%**	**13.45%**	**10.45%**	**10.15%**	**13.33%**
15.		**Average of Adjusted Range**								**8.48%**	**9.36%**	**8.52%**	**8.87%**	**8.70%**	**8.53%**	**8.74%**
16.		**Median of Adjusted Range**								**8.31%**	**8.98%**	**8.45%**	**8.62%**	**8.62%**	**8.49%**	**8.52%**
17.		**75th Percentile, Median of Adjusted Range**								**10.27%**	**11.32%**	**10.03%**	**12.13%**	**10.09%**	**9.86%**	**12.08%**
18.		**Number of Individual Estimates, Adjusted Range**								**32**	**33**	**33**	**28**	**33**	**31**	**190**

Estimated ROEs for Opinion 531 Two-Step DCF

Line No.		Company	Two-Stage Growth Rate	Dividend Yield	Estimated ROEs (Before Screening Against Bond Yield)	Bond Yield Threshold (Moody's Rate plus 100 Basis Points)	Estimated ROEs (Adjusted Range, Screened Against Bond Yield)
1.	ALE	Allete Inc	4.75%	3.08%	7.91%	5.48%	7.91%
2.	ED	Consolidated Edison Inc	4.07%	3.48%	7.63%	5.11%	7.63%
3.	EIX	Edison International	4.16%	2.76%	6.97%	5.48%	6.97%
4.	OGE	OGE Energy Corp	5.62%	3.43%	9.16%	5.11%	9.16%
5.	PCG	Pacific Gas and Electric Company	4.22%	3.03%	7.32%	5.11%	7.32%
6.	PNW	Pinnacle West Capital Corp	5.47%	3.11%	8.68%	5.11%	8.68%
7.	POR	Portland General Electric Company	5.12%	2.88%	8.08%	5.48%	8.08%
8.	VVC	Vectren Corp	5.09%	2.88%	8.04%	5.11%	8.04%
9.	WEC	WEC Energy Group	5.16%	3.42%	8.68%	5.11%	8.68%
10.	XEL	Xcel Energy Inc	4.97%	3.17%	8.22%	5.11%	8.22%
11.		**Adjusted Range, Low Value**					**6.97%**
12.		**Adjusted Range, High Value**					**9.16%**
13.		**Midpoint of Adjusted Range**					**8.07%**
14.		**75th Percentile, Midpoint of Adjusted Range**					**8.61%**
15.		**Average of Adjusted Range**					**8.07%**
16.		**Median of Adjusted Range**					**8.06%**
17.		**75th Percentile, Median of Adjusted Range**					**8.61%**
18.		**Number of Individual Estimates, Adjusted Range**					**10**

Dividend Yield February 2017 through July 2017

Line No.		Name	Dividend Yield Feb-17	Dividend Yield Mar-17	Dividend Yield Apr-17	Dividend Yield May-17	Dividend Yield Jun-17	Dividend Yield Jul-17	Average Dividend Yield Feb 2017 - Jul 2017
1.	ALE	Allete Inc	3.25%	3.22%	3.08%	3.02%	2.93%	2.98%	3.08%
2.	LNT	Alliant Energy Corp	3.30%	3.21%	3.17%	3.12%	3.06%	3.11%	3.16%
3.	AEE	Ameren Corp	3.31%	3.20%	3.21%	3.18%	3.15%	3.19%	3.21%
4.	AEP	American Electric Power Company Inc	3.63%	3.55%	3.50%	3.40%	3.32%	3.40%	3.47%
5.	AGR	AVANGRID Inc.	4.21%	4.03%	3.99%	3.89%	3.84%	3.86%	3.97%
6.	AVA	Avista Corp	3.68%	3.63%	3.58%	3.46%	3.31%	3.04%	3.45%
7.	BKH	Black Hills Corp	2.84%	2.74%	2.65%	2.62%	2.55%	2.58%	2.66%
8.	CNP	CenterPoint Energy Inc	4.04%	3.87%	3.81%	3.85%	3.79%	3.87%	3.87%
9.	CMS	CMS Energy Corp	3.08%	2.98%	2.95%	2.88%	2.82%	2.88%	2.93%
10.	ED	Consolidated Edison Inc	3.68%	3.58%	3.51%	3.41%	3.33%	3.39%	3.48%
11.	D	Dominion Energy	3.76%	3.92%	3.90%	3.83%	3.83%	3.95%	3.87%
12.	DTE	DTE Energy Company	3.33%	3.26%	3.19%	3.10%	3.05%	3.11%	3.17%
13.	DUK	Duke Energy Corp New	4.30%	4.18%	4.16%	4.07%	4.00%	4.07%	4.13%
14.	EIX	Edison International	2.87%	2.73%	2.71%	2.73%	2.71%	2.79%	2.76%
15.	EE	El Paso Electric Co	2.64%	2.53%	2.42%	2.41%	2.51%	2.59%	2.52%
16.	ETR	Entergy Corp	4.75%	4.63%	4.56%	4.51%	4.43%	4.58%	4.58%
17.	ES	Eversource Energy	3.34%	3.23%	3.20%	3.16%	3.07%	3.14%	3.19%
18.	EXC	Exelon Corp	3.66%	3.64%	3.69%	3.76%	3.58%	3.55%	3.64%
19.	FE	FirstEnergy Corp	4.64%	4.57%	4.70%	4.97%	4.88%	4.70%	4.74%
20.	FTS	Fortis Inc	4.95%	4.95%	4.83%	4.94%	4.66%	4.52%	4.81%
21.	HE	Hawaiian Electric Industries Inc	3.75%	3.74%	3.71%	3.77%	3.75%	3.83%	3.76%
22.	IDA	IDACORP Inc	2.72%	2.69%	2.61%	2.59%	2.50%	2.57%	2.61%
23.	MGEE	MGE Energy Inc	1.94%	1.93%	1.90%	1.92%	1.86%	1.89%	1.91%
24.	NWE	NorthWestern Corporation	3.50%	3.64%	3.53%	3.46%	3.37%	3.52%	3.50%
25.	OGE	OGE Energy Corp	3.46%	3.34%	3.46%	3.50%	3.36%	3.46%	3.43%
26.	OTTR	Otter Tail Corp	3.34%	3.44%	3.27%	3.33%	3.14%	3.22%	3.29%
27.	PCG	Pacific Gas and Electric Company	3.07%	2.94%	2.93%	2.93%	3.12%	3.19%	3.03%
28.	PNW	Pinnacle West Capital Corp	3.30%	3.17%	3.10%	3.04%	3.00%	3.06%	3.11%
29.	PNM	PNM Resources Inc	2.76%	2.64%	2.58%	2.60%	2.48%	2.52%	2.60%
30.	POR	Portland General Electric Company	2.92%	2.85%	2.82%	2.79%	2.92%	3.00%	2.88%
31.	PPL	PPL Corporation	4.25%	4.28%	4.20%	4.08%	4.02%	4.16%	4.16%
32.	PEG	Public Service Enterprise Group Inc	3.69%	3.83%	3.83%	3.92%	3.88%	3.95%	3.85%
33.	SCG	SCANA Corporation	3.39%	3.63%	3.69%	3.69%	3.55%	3.83%	3.63%
34.	SRE	Sempra Energy	2.85%	2.98%	2.97%	2.90%	2.86%	2.92%	2.91%
35.	SO	Southern Co	4.55%	4.45%	4.50%	4.64%	4.65%	4.90%	4.61%
36.	VVC	Vectren Corp	3.05%	2.95%	2.83%	2.80%	2.78%	2.85%	2.88%
37.	WEC	WEC Energy Group	3.57%	3.48%	3.44%	3.38%	3.31%	3.36%	3.42%
38.	XEL	Xcel Energy Inc	3.23%	3.27%	3.22%	3.11%	3.05%	3.10%	3.17%

Dividend February 2017 through July 2017

Line No.		Name	Annual Dividend Feb-17	Annual Dividend Mar-17	Annual Dividend Apr-17	Annual Dividend May-17	Annual Dividend Jun-17	Annual Dividend Jul-17
1.	ALE	Allete Inc	2.14	2.14	2.14	2.14	2.14	2.14
2.	LNT	Alliant Energy Corp	1.26	1.26	1.26	1.26	1.26	1.26
3.	AEE	Ameren Corp	1.76	1.76	1.76	1.76	1.76	1.76
4.	AEP	American Electric Power Company Inc	2.36	2.36	2.36	2.36	2.36	2.36
5.	AGR	AVANGRID Inc.	1.73	1.73	1.73	1.73	1.73	1.73
6.	AVA	Avista Corp	1.43	1.43	1.43	1.43	1.43	1.43
7.	BKH	Black Hills Corp	1.78	1.78	1.78	1.78	1.78	1.78
8.	CNP	CenterPoint Energy Inc	1.07	1.07	1.07	1.07	1.07	1.07
9.	CMS	CMS Energy Corp	1.33	1.33	1.33	1.33	1.33	1.33
10.	ED	Consolidated Edison Inc	2.76	2.76	2.76	2.76	2.76	2.76
11.	D	Dominion Energy	2.80	3.02	3.02	3.02	3.02	3.02
12.	DTE	DTE Energy Company	3.30	3.30	3.30	3.30	3.30	3.30
13.	DUK	Duke Energy Corp New	3.42	3.42	3.42	3.42	3.42	3.42
14.	EIX	Edison International	2.17	2.17	2.17	2.17	2.17	2.17
15.	EE	El Paso Electric Co	1.24	1.24	1.24	1.24	1.34	1.34
16.	ETR	Entergy Corp	3.48	3.48	3.48	3.48	3.48	3.48
17.	ES	Eversource Energy	1.90	1.90	1.90	1.90	1.90	1.90
18.	EXC	Exelon Corp	1.31	1.31	1.31	1.31	1.31	1.31
19.	FE	FirstEnergy Corp	1.44	1.44	1.44	1.44	1.44	1.44
20.	FTS	Fortis Inc	1.60	1.60	1.60	1.60	1.60	1.60
21.	HE	Hawaiian Electric Industries Inc	1.24	1.24	1.24	1.24	1.24	1.24
22.	IDA	IDACORP Inc	2.20	2.20	2.20	2.20	2.20	2.20
23.	MGEE	MGE Energy Inc	1.23	1.23	1.23	1.23	1.23	1.23
24.	NWE	NorthWestern Corporation	2.00	2.10	2.10	2.10	2.10	2.10
25.	OGE	OGE Energy Corp	1.21	1.21	1.21	1.21	1.21	1.21
26.	OTTR	Otter Tail Corp	1.28	1.28	1.28	1.28	1.28	1.28
27.	PCG	Pacific Gas and Electric Company	1.96	1.96	1.96	1.96	2.12	2.12
28.	PNW	Pinnacle West Capital Corp	2.62	2.62	2.62	2.62	2.62	2.62
29.	PNM	PNM Resources Inc	0.97	0.97	0.97	0.97	0.97	0.97
30.	POR	Portland General Electric Company	1.28	1.28	1.28	1.28	1.36	1.36
31.	PPL	PPL Corporation	1.52	1.58	1.58	1.58	1.58	1.58
32.	PEG	Public Service Enterprise Group Inc	1.64	1.72	1.72	1.72	1.72	1.72
33.	SCG	SCANA Corporation	2.30	2.45	2.45	2.45	2.45	2.45
34.	SRE	Sempra Energy	3.02	3.29	3.29	3.29	3.29	3.29
35.	SO	Southern Co	2.24	2.24	2.24	2.32	2.32	2.32
36.	VVC	Vectren Corp	1.68	1.68	1.68	1.68	1.68	1.68
37.	WEC	WEC Energy Group	2.08	2.08	2.08	2.08	2.08	2.08
38.	XEL	Xcel Energy Inc	1.36	1.44	1.44	1.44	1.44	1.44

Maximum Stock Price February 2017 through July 2017

Line No.		Name	Max Stock Price Feb-17	Max Stock Price Mar-17	Max Stock Price Apr-17	Max Stock Price May-17	Max Stock Price Jun-17	Max Stock Price Jul-17
1.	ALE	Allete Inc	67.52	68.38	72.05	73.52	74.59	73.76
2.	LNT	Alliant Energy Corp	39.64	40.32	40.22	41.71	42.19	41.66
3.	AEE	Ameren Corp	54.83	56.57	55.68	57.09	57.21	56.67
4.	AEP	American Electric Power Company Inc	67.22	68.25	68.46	71.91	72.97	70.81
5.	AGR	AVANGRID Inc.	43.96	44.11	44.19	45.58	46.13	46.39
6.	AVA	Avista Corp	39.98	40.37	41.48	42.86	44.45	52.83
7.	BKH	Black Hills Corp	65.22	67.02	69.22	69.83	72.02	70.80
8.	CNP	CenterPoint Energy Inc	27.43	28.18	28.86	28.73	29.08	28.34
9.	CMS	CMS Energy Corp	44.72	45.55	45.85	47.70	48.37	47.02
10.	ED	Consolidated Edison Inc	77.24	78.98	80.10	83.25	85.13	82.98
11.	D	Dominion Energy	78.04	79.36	78.46	81.30	81.65	77.57
12.	DTE	DTE Energy Company	101.55	102.96	105.81	109.89	111.35	108.00
13.	DUK	Duke Energy Corp New	82.82	83.59	83.35	86.01	87.49	85.33
14.	EIX	Edison International	79.94	81.34	81.19	81.72	82.82	79.35
15.	EE	El Paso Electric Co	49.00	50.75	52.50	54.10	55.45	53.35
16.	ETR	Entergy Corp	76.79	77.51	77.41	79.48	80.61	77.19
17.	ES	Eversource Energy	59.11	60.36	60.50	62.19	63.34	61.56
18.	EXC	Exelon Corp	37.19	36.63	36.47	36.45	37.44	38.50
19.	FE	FirstEnergy Corp	32.54	32.53	31.94	30.02	30.30	32.35
20.	FTS	Fortis Inc	33.07	33.37	33.99	33.04	35.73	36.60
21.	HE	Hawaiian Electric Industries Inc	33.85	33.94	34.08	33.84	34.08	33.10
22.	IDA	IDACORP Inc	83.99	83.95	86.46	87.50	90.67	87.90
23.	MGEE	MGE Energy Inc	65.18	67.20	66.10	65.33	68.60	68.70
24.	NWE	NorthWestern Corporation	58.74	59.41	60.95	62.04	63.86	61.80
25.	OGE	OGE Energy Corp	36.98	37.41	35.51	35.79	37.25	35.92
26.	OTTR	Otter Tail Corp	39.25	38.70	40.70	40.40	41.95	40.75
27.	PCG	Pacific Gas and Electric Company	66.93	68.29	67.83	68.48	70.32	68.28
28.	PNW	Pinnacle West Capital Corp	82.50	84.72	86.63	88.65	89.56	87.38
29.	PNM	PNM Resources Inc	36.60	37.90	38.39	38.50	40.10	39.90
30.	POR	Portland General Electric Company	45.38	46.05	46.87	47.43	48.06	46.35
31.	PPL	PPL Corporation	37.01	37.95	38.32	40.10	40.20	38.84
32.	PEG	Public Service Enterprise Group Inc	46.14	46.08	45.94	45.27	45.80	45.36
33.	SCG	SCANA Corporation	70.51	70.94	67.87	68.44	71.28	67.99
34.	SRE	Sempra Energy	110.95	113.15	113.96	116.96	117.97	114.95
35.	SO	Southern Co	50.89	51.47	50.48	50.93	51.97	48.05
36.	VVC	Vectren Corp	56.69	59.03	60.47	61.87	62.79	60.24
37.	WEC	WEC Energy Group	60.34	61.53	61.34	62.97	64.37	63.50
38.	XEL	Xcel Energy Inc	43.82	45.06	45.44	48.01	48.50	47.70

Minimum Stock Price February 2017 through July 2017

Line No.		Name	Min Stock Price Feb-17	Min Stock Price Mar-17	Min Stock Price Apr-17	Min Stock Price May-17	Min Stock Price Jun-17	Min Stock Price Jul-17
1.	ALE	Allete Inc	64.23	64.56	66.81	68.07	71.60	69.79
2.	LNT	Alliant Energy Corp	36.80	38.24	39.21	38.95	40.16	39.36
3.	AEE	Ameren Corp	51.61	53.48	54.03	53.72	54.38	53.54
4.	AEP	American Electric Power Company Inc	62.69	64.81	66.50	66.93	69.19	68.11
5.	AGR	AVANGRID Inc.	38.12	41.61	42.42	43.18	43.94	43.13
6.	AVA	Avista Corp	37.78	38.38	38.35	39.77	42.00	41.21
7.	BKH	Black Hills Corp	60.34	62.83	65.37	65.84	67.40	67.08
8.	CNP	CenterPoint Energy Inc	25.51	27.05	27.30	26.87	27.35	26.98
9.	CMS	CMS Energy Corp	41.75	43.61	44.36	44.75	46.02	45.34
10.	ED	Consolidated Edison Inc	72.63	75.11	77.14	78.42	80.67	80.04
11.	D	Dominion Energy	70.87	74.59	76.25	76.39	76.17	75.40
12.	DTE	DTE Energy Company	96.56	99.45	100.97	103.28	105.13	104.19
13.	DUK	Duke Energy Corp New	76.28	80.02	81.27	81.85	83.59	82.72
14.	EIX	Edison International	71.48	77.89	78.85	77.21	77.26	76.38
15.	EE	El Paso Electric Co	45.05	47.35	49.95	48.81	51.15	50.25
16.	ETR	Entergy Corp	69.63	72.79	75.21	74.88	76.52	74.83
17.	ES	Eversource Energy	54.50	57.28	58.27	58.11	60.52	59.55
18.	EXC	Exelon Corp	34.47	35.30	34.53	33.30	35.80	35.37
19.	FE	FirstEnergy Corp	29.58	30.47	29.33	27.93	28.66	28.93
20.	FTS	Fortis Inc	31.59	31.27	32.28	31.72	32.91	34.25
21.	HE	Hawaiian Electric Industries Inc	32.32	32.36	32.82	32.01	32.01	31.71
22.	IDA	IDACORP Inc	78.05	79.90	82.08	82.52	85.20	83.46
23.	MGEE	MGE Energy Inc	61.75	60.35	63.30	62.60	63.80	61.80
24.	NWE	NorthWestern Corporation	55.65	56.08	58.16	59.33	60.94	57.58
25.	OGE	OGE Energy Corp	32.93	34.97	34.37	33.45	34.67	33.95
26.	OTTR	Otter Tail Corp	37.35	35.65	37.50	36.45	39.45	38.75
27.	PCG	Pacific Gas and Electric Company	60.61	65.02	65.80	65.14	65.43	64.84
28.	PNW	Pinnacle West Capital Corp	76.47	80.60	82.62	83.52	84.93	83.95
29.	PNM	PNM Resources Inc	33.75	35.65	36.70	36.00	38.10	37.23
30.	POR	Portland General Electric Company	42.41	43.83	44.04	44.30	45.17	44.20
31.	PPL	PPL Corporation	34.58	35.82	36.91	37.40	38.44	37.19
32.	PEG	Public Service Enterprise Group Inc	42.77	43.77	43.92	42.47	42.79	41.67
33.	SCG	SCANA Corporation	65.08	64.20	64.79	64.48	66.81	60.00
34.	SRE	Sempra Energy	100.79	107.89	107.86	110.03	112.11	110.35
35.	SO	Southern Co	47.57	49.30	49.01	49.15	47.87	46.71
36.	VVC	Vectren Corp	53.65	55.06	58.15	58.03	58.24	57.48
37.	WEC	WEC Energy Group	56.05	58.05	59.61	60.12	61.24	60.47
38.	XEL	Xcel Energy Inc	40.43	42.93	44.00	44.47	45.79	45.18

Short-Term Growth Rates

Line No,		Name	Growth Rate: IBES	Growth Rate: Value Line	Growth Rate: Bloomberg	Growth Rate: Morningstar	Growth Rate: S&P Capital IQ	Growth Rate: Zacks	Weighted Growth Rate (2/3 Short-Term, 1/3 Long-Term): IBES	Weighted: Value Line	Weighted: Bloomberg	Weighted: Morningstar	Weighted: S&P Capital IQ	Weighted: Zacks
1.	ALE	Allete Inc	5.00%	4.96%	7.20%	7.20%	7.20%	6.10%	4.75%	4.73%	6.22%	6.22%	6.22%	5.49%
2.	LNT	Alliant Energy Corp	6.45%	8.67%	5.65%	5.50%	6.00%	5.50%	5.72%	7.20%	5.19%	5.09%	5.42%	5.09%
3.	AEE	Ameren Corp	6.05%	5.48%	5.60%	5.60%	6.00%	6.50%	5.45%	5.08%	5.15%	5.15%	5.42%	5.75%
4.	AEP	American Electric Power Company Inc	2.39%	2.35%	2.50%	*31.2%	5.50%	5.40%	3.01%	2.98%	3.09%	*22.22%	5.09%	5.02%
5.	AGR	AVANGRID Inc.	9.00%	6.79%	9.00%		9.00%	8.50%	7.42%	5.95%	7.42%		7.42%	7.09%
6.	AVA	Avista Corp	5.65%	0.91%		5.30%			5.19%	2.03%		4.95%		
7.	BKH	Black Hills Corp	11.98%	10.07%	6.50%	5.00%	5.00%	5.00%	9.41%	8.14%	5.75%	4.75%	4.75%	4.75%
8.	CNP	CenterPoint Energy Inc	5.89%	10.53%	6.53%	8.10%	6.55%	4.30%	5.35%	8.44%	5.77%	6.82%	5.79%	4.29%
9.	CMS	CMS Energy Corp	7.52%	6.79%	7.43%	7.30%	7.25%	7.00%	6.43%	5.95%	6.38%	6.29%	6.25%	6.09%
10.	ED	Consolidated Edison Inc	3.98%	2.69%	4.50%	3.80%	3.49%	3.50%	4.07%	3.22%	4.42%	3.95%	3.75%	3.75%
11.	D	Dominion Energy	3.46%	5.52%	5.45%	6.80%	6.00%	6.00%	3.73%	5.10%	5.05%	5.95%	5.42%	5.42%
12.	DTE	DTE Energy Company	4.59%	6.92%	5.35%	4.70%	5.90%	5.90%	4.48%	6.04%	4.99%	4.55%	5.35%	5.35%
13.	DUK	Duke Energy Corp New	2.58%	8.19%	4.78%	9.10%	3.92%	4.00%	3.14%	6.88%	4.60%	7.49%	4.03%	4.09%
14.	EIX	Edison International	4.11%	5.91%	6.23%	6.90%	5.00%	6.70%	4.16%	5.36%	5.57%	6.02%	4.75%	5.89%
15.	EE	El Paso Electric Co	6.50%	4.65%	6.50%	5.80%	7.55%	7.60%	5.75%	4.52%	5.75%	5.29%	6.45%	6.49%
16.	ETR	Entergy Corp	-6.47%	-6.18%	-3.83%	-4.20%	7.00%	0.30%	-2.89%	-2.70%	-1.13%	-1.38%	6.09%	1.62%
17.	ES	Eversource Energy	5.65%	6.21%	6.07%	6.10%	6.00%	6.00%	5.19%	5.56%	5.46%	5.49%	5.42%	5.42%
18.	EXC	Exelon Corp	1.26%	12.54%	3.33%	2.90%	5.00%	5.00%	2.26%	9.78%	3.64%	3.35%	4.75%	4.75%
19.	FE	FirstEnergy Corp	-4.19%	5.54%	-2.00%	2.80%	2.00%	-0.40%	-1.37%	5.11%	0.09%	3.29%	2.75%	1.15%
20.	FTS	Fortis Inc	5.26%	9.68%	5.00%		5.00%	5.50%	4.93%	7.87%	4.75%		4.75%	5.09%
21.	HE	Hawaiian Electric Industries Inc	2.70%	-2.67%	3.15%	2.30%	4.15%	4.00%	3.22%	-0.36%	3.52%	2.95%	4.19%	4.09%
22.	IDA	IDACORP Inc	4.00%	3.81%	5.00%	5.00%	5.00%	4.50%	4.09%	3.96%	4.75%	4.75%	4.75%	4.42%
23.	MGEE	MGE Energy Inc	4.00%	8.31%					4.09%	6.96%				
24.	NWE	NorthWestern Corporation	3.02%	3.36%	1.60%	1.20%	1.60%	1.60%	3.43%	3.66%	2.49%	2.22%	2.49%	2.49%
25.	OGE	OGE Energy Corp	6.30%	8.15%	7.40%	7.40%	6.00%	5.30%	5.62%	6.85%	6.35%	6.35%	5.42%	4.95%
26.	OTTR	Otter Tail Corp	5.20%	7.53%	6.55%	6.20%			4.89%	6.44%	5.79%	5.55%		
27.	PCG	Pacific Gas and Electric Company	4.20%	9.72%	3.70%	2.10%	3.85%	5.00%	4.22%	7.90%	3.89%	2.82%	3.99%	4.75%
28.	PNW	Pinnacle West Capital Corp	6.08%	5.86%	5.84%	6.50%	5.85%	5.20%	5.47%	5.32%	5.31%	5.75%	5.32%	4.89%
29.	PNM	PNM Resources Inc	7.35%	8.67%	6.10%	5.20%	5.60%	4.70%	6.32%	7.20%	5.49%	4.89%	5.15%	4.55%
30.	POR	Portland General Electric Company	5.55%	6.79%	3.85%	3.80%	3.35%	3.40%	5.12%	5.95%	3.99%	3.95%	3.65%	3.69%
31.	PPL	PPL Corporation	1.21%	-0.29%	1.20%	0.40%	5.50%	5.00%	2.23%	1.23%	2.22%	1.69%	5.09%	4.75%
32.	PEG	Public Service Enterprise Group Inc	-0.39%	4.34%	3.20%	3.80%	3.00%	2.40%	1.16%	4.31%	3.55%	3.95%	3.42%	3.02%
33.	SCG	SCANA Corporation	6.00%	3.75%	4.07%	4.60%	4.75%	4.70%	5.42%	3.92%	4.13%	4.49%	4.59%	4.55%
34.	SRE	Sempra Energy	9.35%	12.08%	10.67%	16.60%	9.25%	8.70%	7.65%	9.48%	8.53%	12.49%	7.59%	7.22%
35.	SO	Southern Co	3.12%	4.34%	4.77%	4.50%	5.00%	4.30%	3.50%	4.31%	4.60%	4.42%	4.75%	4.29%
36.	VVC	Vectren Corp	5.50%	5.61%	5.50%		6.00%	5.70%	5.09%	5.16%	5.09%		5.42%	5.22%
37.	WEC	WEC Energy Group	5.61%	4.85%	5.55%	6.10%	5.25%	5.50%	5.16%	4.65%	5.12%	5.49%	4.92%	5.09%
38.	XEL	Xcel Energy Inc	5.32%	4.47%	5.70%	6.10%	5.58%	5.40%	4.97%	4.40%	5.22%	5.49%	5.14%	5.02%

* These growth rates were removed from final results

Long-Term Growth Rates: U.S. GDP

Line No.	Source	Year Beginning	Nominal GDP ($Bil)	Year Ending	Nominal GDP ($Bil)	Annual GDP Growth %	Source
1	IHS Global Insight	2018	$20,331	2047	$66,457	4.17%	IHS Global Insight May 2017 Forecast
2	EIA	2018	$20,334	2050	$75,988	4.21%	http://www.eia.gov/beta/aeo/#/?id=18-AEO2017
3	SSA	2018	$20,531	2095	$564,614	4.40%	http://www.ssa.gov/oact/tr/2017/VI_G2_OASDHI_GDP.html#200732
	Average					**4.26%**	

Information to Screen Companies for Opinion 531 Two-Step DCF Proxy Group

Line No.	Ticker	Company Name	Proxy Group Tickers	Proxy Group Names	Include in Proxy Group	Credit Rating Screen	S&P Credit Rating Screen	Moody's Credit Rating Screen	Dividend Screen Feb 2017 Jul 2017	Merger Screen Feb 2017 Jul 2017	S&P Issuer Credit Rating	Moody's Issuer Credit Rating
1	ALE	Allete Inc	ALE	Allete Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	A3
2	LNT	Alliant Energy Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa1
3	AEE	Ameren Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
4	AEP	American Electric Power Company			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa1
5	AGR	AVANGRID Inc.			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
6	AVA	Avista Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa1
7	BKH	Black Hills Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa2
8	CNP	CenterPoint Energy Inc			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa1
9	CMS	CMS Energy Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
10	ED	Consolidated Edison Inc	ED	Consolidated Edison Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
11	D	Dominion Energy			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa2
12	DTE	DTE Energy Company			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
13	DUK	Duke Energy Corp New			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa1
14	EIX	Edison International	EIX	Edison International	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	A3
15	EE	El Paso Electric Co			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa1
16	ETR	Entergy Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa2
17	ES	Eversource Energy			FALSE	FALSE	FALSE	FALSE	TRUE	TRUE	A	Baa1
18	EXC	Exelon Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa2
19	FE	FirstEnergy Corp			FALSE	FALSE	FALSE	FALSE	TRUE	TRUE	BBB-	Baa3
20	FTS	Fortis Inc			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa3
21	GXP	Great Plains Energy Inc			FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	BBB+	Baa2
22	HE	Hawaiian Electric Industries Inc			FALSE	FALSE	FALSE	#N/A	TRUE	TRUE	BBB-	#N/A
23	IDA	IDACORP Inc			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa1
24	MGEE	MGE Energy Inc			FALSE	FALSE	FALSE	#N/A	TRUE	TRUE	AA-	#N/A
25	NEE	NextEra Energy Inc			FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	A-	Baa1
26	NWE	NorthWestern Corporation			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa1
27	OGE	OGE Energy Corp	OGE	OGE Energy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
28	OTTR	Otter Tail Corp			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB	Baa2
29	PCG	Pacific Gas and Electric Company	PCG	Pacific Gas and Electric Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
30	PNW	Pinnacle West Capital Corp	PNW	Pinnacle West Capital Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
31	PNM	PNM Resources Inc			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa3
32	POR	Portland General Electric Company	POR	Portland General Electric Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	A3
33	PPL	PPL Corporation			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa2
34	PEG	Public Service Enterprise Group Inc			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
35	SCG	SCANA Corporation			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa3
36	SRE	Sempra Energy			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
37	SO	Southern Co			FALSE	FALSE	TRUE	FALSE	TRUE	TRUE	A-	Baa2
38	VVC	Vectren Corp	VVC	Vectren Corp	TRUE	TRUE	TRUE	#N/A	TRUE	TRUE	A-	#N/A
39	WEC	WEC Energy Group	WEC	WEC Energy Group	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
40	WR	Westar Energy Inc			FALSE	FALSE	TRUE	FALSE	TRUE	FALSE	BBB+	Baa1
41	XEL	Xcel Energy Inc	XEL	Xcel Energy Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3

Information to Screen Companies for Expanded Two-Step Proxy Group (All Investment Grade)

Line No.	Ticker	Company Name	Proxy Group Tickers	Proxy Group Names	Include in Proxy Group	Electric Utility	Credit Rating Screen	S&P Credit Rating Screen	Moody's Credit Rating Screen	Dividend Screen Feb 2017 Jul 2017	Merger Screen Feb 2017 Jul 2017	Analyst Screen	IBES Growth Rate	S&P Issuer Credit Rating	Moody's Issuer Credit Rating
1	ALE	Allete Inc	ALE	Allete Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	A3
2	LNT	Alliant Energy Corp	LNT	Alliant Energy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa1
3	AEE	Ameren Corp	AEE	Ameren Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
4	AEP	American Electric Power Company	AEP	American Electric Power Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa1
5	AGR	AVANGRID Inc.	AGR	AVANGRID Inc.	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
6	AVA	Avista Corp	AVA	Avista Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa1
7	BKH	Black Hills Corp	BKH	Black Hills Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa2
8	CNP	CenterPoint Energy Inc	CNP	CenterPoint Energy Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa1
9	CMS	CMS Energy Corp	CMS	CMS Energy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
10	ED	Consolidated Edison Inc	ED	Consolidated Edison Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
11	D	Dominion Energy	D	Dominion Energy	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa2
12	DTE	DTE Energy Company	DTE	DTE Energy Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
13	DUK	Duke Energy Corp New	DUK	Duke Energy Corp New	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa1
14	EIX	Edison International	EIX	Edison International	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	A3
15	EE	El Paso Electric Co	EE	El Paso Electric Co	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa1
16	ETR	Entergy Corp	ETR	Entergy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa2
17	ES	Eversource Energy	ES	Eversource Energy	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A	Baa1
18	EXC	Exelon Corp	EXC	Exelon Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa2
19	FE	FirstEnergy Corp	FE	FirstEnergy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB-	Baa3
20	FTS	Fortis Inc	FTS	Fortis Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa3
21	GXP	Great Plains Energy Inc			FALSE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa2
22	HE	Hawaiian Electric Industries Inc	HE	Hawaiian Electric Industries Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB-	#N/A
23	IDA	IDACORP Inc	IDA	IDACORP Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa1
24	MGEE	MGE Energy Inc	MGEE	MGE Energy Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	AA-	#N/A
25	NEE	NextEra Energy Inc			FALSE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	TRUE	A-	Baa1
26	NWE	NorthWestern Corporation	NWE	NorthWestern Corporation	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa1
27	OGE	OGE Energy Corp	OGE	OGE Energy Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
28	OTTR	Otter Tail Corp	OTTR	Otter Tail Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	Baa2
29	PCG	Pacific Gas and Electric Company	PCG	Pacific Gas and Electric Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
30	PNW	Pinnacle West Capital Corp	PNW	Pinnacle West Capital Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
31	PNM	PNM Resources Inc	PNM	PNM Resources Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa3
32	POR	Portland General Electric Company	POR	Portland General Electric Company	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB	A3
33	PPL	PPL Corporation	PPL	PPL Corporation	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa2
34	PEG	Public Service Enterprise Group Inc	PEG	Public Service Enterprise Group Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
35	SCG	SCANA Corporation	SCG	SCANA Corporation	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa3
36	SRE	Sempra Energy	SRE	Sempra Energy	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	BBB+	Baa1
37	SO	Southern Co	SO	Southern Co	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	Baa2
38	VVC	Vectren Corp	VVC	Vectren Corp	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	#N/A
39	WEC	WEC Energy Group	WEC	WEC Energy Group	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3
40	WR	Westar Energy Inc			FALSE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	TRUE	TRUE	BBB+	Baa1
41	XEL	Xcel Energy Inc	XEL	Xcel Energy Inc	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	A-	A3

Merger Screen

Line No.	Ticker	Company Name	M&A Activity	Beginning Date	Ending Date	Comments
1	AYE	Allegheny Energy	TRUE	2/11/2010	2/26/2011	First Energy and Allegheny Energy announced a merger February 11, 2010. AYE shareholders will receive 0.667 FE shares for one AYE share.
2	ALE	ALLETE	FALSE	1/1/1900	1/1/1900	
3	LNT	Alliant Energy	FALSE	1/1/1900	1/1/1900	
4	AEP	Amer. Elec. Power	FALSE	1/1/1900	1/1/1900	
5	AEP1	Amer. Elec. Power	FALSE	9/14/2016	12/31/2099	AEP is selling four competitive power plants in a transaction valued at about $2.2 billion. This is less than five percent of AEP's assets.
6	AEE	Ameren Corp.	FALSE	1/1/1900	1/1/1900	
7	AGR	AVANGRID Inc.	FALSE	1/1/1900	1/1/1900	
8	AVA	Avista Corp.	FALSE	1/1/1900	1/1/1900	
9	BKH	Black Hills	TRUE	7/12/2015	2/12/2016	BKH announced its purchase of SourceGas for $1.89billion on 7/12/15 and completed the transaction on 2/12/16.
10	CV	Cen. Vermont Pub. Serv.	FALSE	1/1/1900	1/1/1900	
11	CNP	CenterPoint Energy	FALSE	1/1/1900	1/1/1900	
12	CHG	CH Energy Group	FALSE	1/1/1900	1/1/1900	
13	CNL	Cleco Corp.	TRUE	10/20/2014	12/31/2099	Investor group to acquire Cleco Corporation for $55.37 per share in cash. The company will continue to operate under the "Cleco" brand and name. The transaction closed in April 2016.
14	CMS	CMS Energy Corp.	FALSE	1/1/1900	1/1/1900	
15	ED	Consol. Edison	FALSE	1/1/1900	1/1/1900	
16	CEG	Constellation Energy	TRUE	4/28/2011	3/12/2012	On April 28, 2011, Exelon and Constellation announced that the two companies are to merge in a stock-for-stock transaction that is expected to close early 2012.
17	CEG1	Constellation Energy	TRUE	9/18/2008	11/6/2009	Mid-American Energy Holdings acquisition of Constellation Energy announced September 18, 2008. That agreement terminated upon acceptance of a competing agreement with EDF. The EDF agreement included a sale of a 49.99% share of Constellation's nuclear assets to EDF. That sale closed on or about November 6, 2009.
18	CEG2	Constellation Energy	TRUE	8/7/2010	12/31/2099	On August 7, 2010, Constellation Energy announced the potential purchase of natural gas-fired plants in New England for approximately $1.1 billion. At June 30, 2010, Constellation's assets were approximately $21.7 billion, so the acquisition is approximately 5.1% of CEG assets.
19	CEG3	Constellation Energy	TRUE	4/28/2011	12/31/2099	On April 28, 2011, Exelon and Constellation announced that the two companies are to merge in a stock-for-stock transaction that is expected to close early 2012.
20	D	Dominion Resources	TRUE	2/1/2016	9/14/2016	Dominion and Questar merged in a $6.1 billion transaction.
21	DPL	DPL Inc.	TRUE	4/20/2011	12/31/2099	On April 20, 2011, AES Corp. announced that it was acquiring DPLfor $30 per share in cash, or $4.7 billion total (including $1.2 billion of debt). Transcation is expceted to close within 9 months (around January 2012).
22	DTE	DTE Energy	FALSE	1/1/1900	1/1/1900	
23	DTE1	DTE Energy	FALSE	9/26/2016	10/20/2016	DTE Energy announced the purchase of $1.3 billion in midstream natural gas assets. This transaction is less than five percent of DTE Energy's total assets.
24	DUK	Duke Energy	TRUE	10/26/2015	10/3/2016	Duke Energy purchased Piedmont Natural Gas in a $6.7 billion transaction, including assumption of debt.
25	DUK1	Duke Energy	TRUE	1/10/2011	7/2/2012	On January 10, 2011, Duke Energy and Progress Energy announced that they have decided to merge. The companies expect the deal to close by year-end 2011.
26	EIX	Edison Int'l	FALSE	1/1/1900	1/1/1900	
27	EE	El Paso Electric	FALSE	1/1/1900	1/1/1900	
28	EDE	Empire Dist. Elec.	TRUE	2/9/2016	12/31/2099	Algonquin Power & Utilities Corporation is purchasing EDE for its Liberty Utilities unit.
29	ES	Northeast Utilities	TRUE	10/18/2010	4/11/2012	Hartford's Northeast Utilities has agreed to take control of Boston-based NStar in a stock-for-stock deal that brings together about $17.5 billion in stock market value and debt from the combined companies.
30	ETR	Entergy Corp.	TRUE	8/7/2008	4/5/2010	Spinoff of nuclear units targeted for 2008 Q4 (ETR 10-Q, 8/7/2008). Existing shareholders receive all shares in spinoff. Value Line suspended projecting ETR data after Hurricane Ike (Value Line 9/26/2008 sheet for ETR.) ETR announced unwinding of spinoff on April 5, 2010.
31	EXC	Exelon Corp.	TRUE	4/30/2014	3/23/2016	On April 30, 2014, Exelon announced its plans to acquire PEPCO with an all-cash transaction based on a $27.25 share price. This values the deal at about $6.8 billion. The acquisition closed in March 2016.
32	EXC1	Exelon Corp.	TRUE	10/20/2008	7/22/2009	Exelon made offer for NRG on October 20, 2008; withdrew offer on July 22, 2009.
33	EXC2	Exelon Corp.	TRUE	4/28/2011	3/12/2012	On April 28, 2011, Exelon and Constellation announced that the two companies are to merge in a stock-for-stock transaction. The merger closed on March 12, 2012.
34	EXC3	Exelon Corp.	TRUE	4/30/2014	12/31/2099	On April 30, 2014, Exelon announced its plans to acquire PEPCO with an all-cash transaction based on a $27.25 share price. This values the deal at about $6.8 billion. The DC Public Service Commission denied Exelon's merger with PEPCO on 8/25/15. In September 2015, Exelon filed a request with the Commission for an appeal on the merger.
35	FE	FirstEnergy Corp.	TRUE	2/11/2010	2/26/2011	First Energy and Allegheny Energy announced a merger February 11, 2010. AYE shareholders will receive 0.667 FE shares for one AYE share.
36	FTS	Fortis Inc	TRUE	2/9/2016	10/14/2016	Fortis acquired ITC Holdings for approximately $11.3 billion. The transaction was completed on Oct 14, 2016.
37	FPL	FPL Group	FALSE	1/1/1900	1/1/1900	

Line No.	Ticker	Company Name	M&A Activity	Beginning Date	Ending Date	Comments
38	GXP	G't Plains Energy	TRUE	5/13/2016	12/31/2017	Great Plains Energy is acquiring Westar Energy in a $12.2 billion transaction.
39	GXP1	G't Plains Energy	TRUE	2/1/2007	7/31/2008	Great Plains Energy acquired Aquila, Inc. in July 2008. Transaction was announced in February 2007.
40	HE	Hawaiian Elec.	TRUE	12/3/2014	12/31/2015	NextERA acquires Hawaiian Electric for $4.3billion, includes the assumption of $1.7bil in HEI debt and excludes HEI's banking subsidiary. The transaction is expected to be completed within 12 months.
41	IDA	IDACORP, Inc.	FALSE	1/1/1900	1/1/1900	
42	TEG	Integrys Energy	TRUE	6/23/2014	10/1/2015	Wisconsin Energy to acquire Integrys Energy Group for $9.1 billion in cash, stock and assumed debt. The companies expect closing by the summer of 2015.
43	TEG1	Integrys Energy	TRUE	12/23/2009	3/31/2010	Purchase and sale agreement with Macquarie Cook Power to sell commodity contracts comprising wholesale electric marketing and trading business. Assets involved in sale are approximately $1.85 billion, about 15 percent of Integrys Energy's assets. The sale closed on March 31, 2010.
44	TEG2	Integrys Energy	TRUE	6/23/2014	12/31/2099	Wisconsin Energy to acquire Integrys Energy Group for $9.1 billion in cash, stock and assumed debt. Acquisition completed on 6/29/15
45	ITC	ITC Holdings	TRUE	2/9/2016	12/31/2099	Fortis to acquire ITC Holdings for approximately $11.3 billion. Fortis will apply to list its common shares on the NYSE.
46	MGEE	MGE Energy	FALSE	1/1/1900	1/1/1900	
47	NEE	NextEra Energy	TRUE	7/29/2016	12/31/2017	NextEra acquires Energy Future Holdings Corporation out of bankruptcy. The transaction is valued at approximately $18.7 billion, when a second related transaction is included.
48	NEE1	NextEra Energy	TRUE	12/3/2014	7/18/2016	NextERA acquires Hawaiian Electric for $4.3billion, includes the assumption of $1.7bil in HEI debt and excludes HEI's banking subsidiary. The transaction was essentially denied by the Hawaii Commission in July 2016.
49	NU	Northeast Utilities	TRUE	10/18/2010	4/11/2012	Hartford’s Northeast Utilities has agreed to take control of Boston-based NStar in a stock-for-stock deal that brings together about $17.5 billion in stock market value and debt from the combined companies.
50	NWE	NorthWestern Corporation	TRUE	9/26/2013	11/18/2014	Purchased 633 MW of hydro facilities from PPL Montana for $903 million
51	NST	NSTAR	TRUE	10/18/2010	4/11/2012	Hartford’s Northeast Utilities has agreed to take control of Boston-based NStar in a stock-for-stock deal that brings together about $17.5 billion in stock market value and debt from the combined companies.
52	NVE	NV Energy Inc.	TRUE	5/29/2013	12/31/2099	NV Energy agreed to be acquired by MidAmerican Energy (Berkshire Hathaway).
53	OGE	OGE Energy	FALSE	1/1/1900	1/1/1900	
54	OTTR	Otter Tail Corp.	FALSE	1/1/1900	1/1/1900	
55	POM	Pepco Holdings	TRUE	4/30/2014	12/31/2099	On April 30, 2014, Exelon announced its plans to acquire PEPCO with an all-cash transaction based on a $27.25 share price. This values the deal at about $6.8 billion.
56	POM1	Pepco Holdings	TRUE	4/20/2010	7/1/2010	Pepco Holdings announced sale of Conectiv generating assets to Calpine, April 20, 2010. The sale was completed on July 1, 2010.
57	POM2	Pepco Holdings	TRUE	4/30/2014	12/31/2099	On April 30, 2014, Exelon announced its plans to acquire PEPCO with an all-cash transaction based on a $27.25 share price. This values the deal at about $6.8 billion.
58	PCG	PG&E Corp.	FALSE	1/1/1900	1/1/1900	
59	PNW	Pinnacle West Capital	FALSE	1/1/1900	1/1/1900	
60	PNM	PNM Resources	FALSE	1/1/1900	1/1/1900	
61	POR	Portland General	FALSE	1/1/1900	1/1/1900	
62	PPL	PPL Corp.	TRUE	6/1/2014	6/1/2015	In June 2014, PPL announced its spinoff of PPL Energy Supply, and this spinoff was completed on 6/1/15. Following the spinoff, PPL Energy Supply combined with affiliates of Riverstone to form Talen Energy. Technically, this is not M&A, but we're being conservative in this case and taking the company out of the proxy group.
63	PPL1	PPL Corp.	TRUE	4/29/2010	10/31/2010	PPL announced purchase of E.ON-US utility assets in Kentucky on April 29, 2010. On September 16, 2010, PPL announced that it anticipated closing the transaction by October 31, 2010.
64	PGN	Progress Energy	TRUE	1/10/2011	7/2/2012	On January 10, 2011, Duke Energy and Progress Energy announced that they have decided to merge. The companies expect the deal to close by year-end 2011.
65	PEG	Public Serv. Enterprise	FALSE	1/1/1900	1/1/1900	
66	SCG	SCANA Corp.	FALSE	1/1/1900	1/1/1900	
67	SRE	Sempra Energy	FALSE	1/1/1900	1/1/1900	Acquisition of EnergySouth announced 7/28/2008. ENSI assets are approximately 2.9% of SRE assets.
68	SO	Southern Co.	TRUE	8/24/2015	7/1/2016	Southern Company agreed to acquire AGL Resources for $12 billion in cash and debt on 8/24/15. The transaction was completed in July 2016.
69	SO1	Southern Co.	FALSE	7/10/2016	12/31/2099	Southern Company agreed to purchase a 50% interest in Southern Natural Gas. The transaction is worth approximately $1.5 billion, which is less than 5 percent of Southern's assets.
70	TE	TECO Energy	TRUE	9/4/2015	12/31/2099	Emera announced acquiring TECO on 9/4/15.
71	UIL	UIL Holdings	TRUE	2/25/2015	12/31/2099	Iberdrola USA and UIL Holdings have a definitive agreement to create a newly listed U.S. public-traded company. The transaction closed in December 2015 and created Avangrid (AGR).
72	UIL1	UIL Holdings	TRUE	5/25/2010	11/17/2010	UIL Holdings entered into a purchase agreement to acquire Connecticut Energy Corporation, Connecticut Natural Gas Corporation and The Berkshire Gas Company from Iberdrola USA, Inc. for $1.3 billion on May 25, 2010.
73	UNS	UniSource Energy	TRUE	12/11/2013	12/31/2099	Fortis to acquire UNS Energy for $60.25 per common share in cash, representing an aggregate purchase price of approximately US$4.3 billion, including
74	VVC	Vectren Corp.	FALSE	1/1/1900	1/1/1900	
75	WR	Westar Energy	TRUE	5/13/2016	12/31/2017	Great Plains Energy is acquiring Westar Energy in a $12.2 billion transaction.
76	WEC	Wisconsin Energy	TRUE	6/23/2014	6/29/2015	Wisconsin Energy to acquire Integrys Energy Group for $9.1 billion in cash, stock and assumed debt. Acquisition completed on 6/29/15
77	XEL	Xcel Energy Inc.	FALSE	1/1/1900	1/1/1900	

Moody's Long-Term Utility Bond Yields

Month	**Aa Rate (%)**	**A Rate (%)**	**Baa Rate (%)**
February 2017	3.99	4.18	4.58
March 2017	4.04	4.23	4.62
April 2017	3.93	4.12	4.51
May 2017	3.94	4.12	4.5
June 2017	3.77	3.94	4.32
July 2017	3.88	4.05	4.36
6-Month Historical Period Average	3.93%	4.11%	4.48%

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

<u>EXHIBIT SCE-19</u>

EXHIBIT TO THE TESTIMONY OF
DR. PAUL T. HUNT

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Southern California Edison Company
Comparable Earnings Analysis
Summary

Market-To-Book

Median	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Median	
Regulated	1.8	1.4	1.2	1.4	1.4	1.5	1.5	1.6	1.6	1.7	**1.52**	(See Page 7 of Exhibit SCE-19)
Unregulated	4.2	3.4	3.0	3.2	3.2	3.4	3.7	4.2	4.7	4.9	**3.55**	(See Page 21 of Exhibit SCE-19)

PEs

Median	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Median	
Regulated	16.5	14.2	12.7	12.9	14.2	15.2	16.2	16.0	17.7	18.7	**15.6**	(See Page 2 of Exhibit SCE-19)
Unregulated	19.3	17.1	14.3	14.8	15.0	15.6	17.5	19.1	20.6	21.0	**17.3**	(See Page 9 of Exhibit SCE-19)

Projected Unregulated ROE = PE/BV: **35.14%**

Explanation

The following symbols are utilized below:

ROE = Return on Equity
M/B = Market-to-Book Ratio
P/E = Price/Earnings Ratio

Per Share
B = Book Value of Equity per Share
E = Earnings per Share
P = Stock Price

ROE $= \frac{E}{B}$ (Return on Equity = Earnings ÷ Book Value of Equity)

M/B $= \frac{P}{B}$ (Market-to-Book Ratio = Stock Price ÷ Book Value of Equity)

P/E $= \frac{P}{E}$ (Price / Earnings Ratio = Stock Price ÷ Earnings per Share)

Since $$\frac{E}{B} = \frac{\frac{P}{B}}{\frac{P}{E}} = \text{ROE} = \frac{(M/B)}{(P/E)}$$

(Return on Equity = Market-to-Book Ratio ÷ Price / Earnings Ratio)

It follows that $$\frac{ROE_R}{ROE_U} = \frac{\frac{(M/B)_R}{(P/E)_R}}{\frac{(M/B)_U}{(P/E)_U}} = \frac{(M/B)_R}{(P/E)_R} \text{ X } \frac{(P/E)_U}{(M/B)_U} \textbf{ or } \frac{(M/B)_R}{(M/B)_U} \text{ X } \frac{(P/E)_U}{(P/E)_R}$$

This formula can be described as follows:
The ratio of a regulated utility reference group ROE to an unregulated reference group ROE should equal the ratio of the regulated group's M/B ratio to the unregulated group's M/B ratio multiplied by the ratio of the unregulated group's P/E ratio to the regulated group's P/E ratio.

The conversion factor is calculated as follows:

$$\text{Conversion Factor} = \frac{ROE_R}{ROE_U} = \frac{(M/B)_R}{(M/B)_U} \text{ X } \frac{(P/E)_U}{(P/E)_R}$$

Subscripts
R = Regulated
U = Unregulated

$$47.34\% = \frac{1.52}{3.55} \text{ X } \frac{17.3}{15.6}$$

Applying the conversion factor to the projected unregulated ROE results in the ROE estimate for SCE:

Estimated ROE = Unregulated ROE Project * Risk Conversion Factor

Estimated ROE = 35.14% * 47.34% = 16.64%

(See Page 33 of Exhibit SCE-19)

Southern California Edison Company
Comparable Earnings Analysis
Regulated Utility Reference Group - Input Data

Index	Ticker Symbols	Company Name	Beta	Book Value per Share (Long) 2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Average Annual P/E Ratio 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	ALE	ALLETE	0.8	21.9	24.11	25.37	26.41	27.26	28.78	30.48	32.44	35.06	37.07	38.17	14.8	13.9	16.1	16	14.7	15.9	18.6	17.2	15.1	18.6
2	AEP	AMERICAN ELEC. PWR.	0.65	23.7	25.17	26.33	27.49	28.33	30.33	31.37	32.98	34.37	36.44	35.38	16.3	13.1	10	13.4	11.9	13.8	14.5	15.9	15.8	15.2
3	AVA	AVISTA CORP.	0.7	17.5	17.27	18.3	19.17	19.71	20.3	21.06	21.61	23.84	24.53	25.69	30.9	15	11.4	12.7	14.1	19.3	14.6	17.3	17.6	18.8
4	CNP	CENTERPOINT EN'RGY	0.85	4.96	5.61	5.89	6.74	7.53	9.91	10.06	10.09	10.6	8.05	8.03	15	11.3	11.8	13.8	14.6	14.8	18.7	17	18.1	21.9
5	CMS	CMS ENERGY CORP.	0.65	10	9.46	10.88	11.42	11.19	11.92	12.09	12.98	13.34	14.21	15.23	26.8	10.9	13.6	12.5	13.6	15.1	16.3	17.3	18.3	20.9
6	ED	CON. EDISON	0.5	31.1	32.58	35.43	36.46	37.93	39.05	40.53	41.81	42.94	44.55	46.88	13.8	12.3	12.5	13.3	15.1	15.4	14.7	15.9	15.6	18.8
7	D	DOMINION RES.	0.65	18.5	16.31	17.28	18.66	20.66	20.09	18.34	20.02	19.74	21.24	23.26	20.6	13.8	12.7	14.3	17.3	18.9	19.2	23	22.1	21.3
8	DTE	DTE ENERGY CO.	0.65	33	35.86	36.77	37.96	39.67	41.41	42.78	44.73	47.05	48.88	50.22	18.3	14.8	10.4	12.3	13.5	14.9	17.9	14.9	18.1	19
9	EIX	EDISON INTERNAT'L	0.6	23.7	25.92	29.21	30.2	32.44	30.86	28.95	30.5	33.64	34.89	36.82	16	12.4	9.7	10.3	11.8	9.7	12.7	13	14.8	17.9
10	EE	EL PASO ELECTRIC	0.75	12.6	14.76	15.47	16.45	19.04	19.03	20.57	23.44	24.39	25.13	26.52	15.3	11.9	10.8	10.7	12.6	14.5	15.9	16.4	18.3	18.7
11	ETR	ENTERGY CORP.	0.65	40.5	40.71	42.07	45.54	47.53	50.81	51.73	54	55.83	51.89	45.12	19.3	16.6	12	11.6	9.1	11.2	13.2	12.9	12.5	10.9
12	ES	EVERSOURCE ENERGY	0.65	18.1	18.65	19.38	20.37	21.6	22.65	29.41	30.49	31.47	32.64	33.8	18.7	13.7	12	13.4	15.4	19.9	16.9	17.9	18.1	18.7
13	EXC	EXELON CORP.	0.65	14.9	15.34	16.78	19.16	20.49	21.68	25.07	26.52	26.29	28.04	27.96	18.2	18	11.5	11	11.3	19.1	13.4	16	12.6	18.7
14	FE	FIRSTENERGY	0.65	28.3	29.45	27.17	28.08	28.03	31.75	31.29	30.32	29.49	29.33	14.11	15.6	15.6	13	11.7	22.4	21.1	13.1	39.8	17	15.9
15	FTS	FORTIS INC.	0.65	12.3	16.72	18	18.57	18.95	20.53	20.84	22.39	24.9	28.63	32.32	21.1	17.5	16.4	18.2	18.8	20.1	20	24.3	18	21.6
16	GXP	GREAT PLAINS EN'GY	0.75	16.7	18.18	21.39	20.62	21.26	21.74	21.75	22.58	23.26	23.68	24.73	16.3	20.5	16	12.1	16.1	15.5	14.2	16.5	19.4	18
17	HE	HAWAIIAN ELECTRIC	0.7	13.4	15.29	15.35	15.58	15.67	15.95	16.28	17.06	17.47	17.94	19.03	21.6	23.2	19.8	18.6	17.1	15.8	16.2	15.9	20.4	13.6
18	IDA	IDACORP, INC.	0.7	25.8	26.79	27.76	29.17	31.01	33.19	35.07	36.84	38.85	40.88	42.74	18.2	13.9	10.2	11.8	11.5	12.4	13.4	14.7	16.2	19.1
19	MGEE	MGE ENERGY INC.	0.75	11.9	12.99	13.92	14.47	15.14	15.89	16.71	17.81	19.02	19.92	20.89	15	14.2	15.1	15	15.8	17.2	17	17.2	20.3	24.9
20	NEE	NEXTERA ENERGY	0.65	24.5	26.35	28.57	31.35	34.36	35.92	37.9	41.47	44.96	48.97	52.01	18.9	14.5	13.4	10.8	11.5	14.4	16.6	17.3	16.9	20.7
21	NWE	NORTHWESTERN	0.65	20.7	21.12	21.25	21.86	22.64	23.68	25.09	26.6	31.5	33.22	34.68	21.7	13.9	11.5	12.9	12.6	15.7	16.9	16.2	18.4	17.2
22	OGE	OGE ENERGY CORP.	0.95	8.79	9.16	10.14	10.52	11.73	13.06	14	15.3	16.27	16.66	17.24	13.8	12.4	10.8	13.3	14.4	15.2	17.7	18.3	17.7	17.7
23	OTTR	OTTER TAIL CORP.	0.9	16.7	17.55	19.14	18.78	17.57	15.83	14.43	14.75	15.39	15.98	17.03	19	30.1	31.2	55.1	47.5	21.7	21.1	18.8	18.2	20.2
24	PCG	PG&E CORP.	0.65	22.4	24.18	25.97	27.88	28.55	29.35	30.35	31.41	33.09	33.69	35.39	16.8	12.1	13	15.8	15.5	20.7	23.7	15	26.4	21.1
25	PNW	PINNACLE WEST	0.65	34.5	35.15	34.16	32.69	33.86	34.98	36.2	38.07	39.5	41.3	43.15	14.9	16.1	13.7	12.6	14.6	14.3	15.3	15.9	16	18.7
26	POR	PORTLAND GENERAL	0.7	19.6	21.05	21.64	20.5	21.14	22.07	22.87	23.3	24.43	25.43	26.35	11.9	16.3	14.4	12	12.4	14	16.9	15.3	17.7	19.1
27	PPL	PPL CORPORATION	0.7	13.3	14.88	13.55	14.57	16.98	18.72	18.01	19.78	20.47	14.72	14.56	17.3	17.6	25.7	11.9	10.5	10.9	12.8	14.1	13.9	12.8
28	PEG	P.S. ENTERPRISE GP.	0.65	13.4	14.35	15.36	17.37	19.04	20.3	21.31	22.95	24.09	25.86	26.01	16.5	13.6	10	10.4	10.4	12.8	13.5	12.6	12.4	15.3
29	SCG	SCANA CORP.	0.65	24.4	25.37	25.85	27.63	29.05	29.94	31.47	33.08	34.95	38.09	40.06	15	12.7	11.6	12.9	13.7	14.8	14.4	13.7	14.7	16.8
30	SO	SOUTHERN COMPANY	0.55	15.2	16.23	17.08	18.15	19.21	20.32	21.09	21.43	21.98	22.59	25	16	16.1	13.5	14.9	15.8	17	16.2	16	15.8	17.8
31	WEC	WEC ENERGY GROUP	0.6	12.4	13.25	14.27	15.26	16.26	17.2	18.05	18.73	19.6	27.42	28.29	16.5	14.8	13.3	14	14.2	15.8	16.5	17.7	21.3	19.9
32	WR	WESTAR ENERGY	0.7	17.6	19.14	20.18	20.59	21.25	22.03	22.89	23.88	25.02	25.87	26.84	14.1	17	14.9	13	14.8	13.4	14	15.4	18.5	21.6
33	XEL	XCEL ENERGY	0.6	14.3	14.7	15.35	15.92	16.76	17.44	18.19	19.21	20.2	20.89	21.73	16.7	13.7	12.7	14.1	14.2	14.8	15	15.4	16.5	18.5
															Median									
															16.5	14.2	12.7	12.9	14.2	15.2	16.2	16.0	17.7	18.7

Southern California Edison Company
Comparable Earnings Analysis
Regulated Utility Reference Group - Input Data

Index	Ticker Symbols	Company Name	Beta	High Stock Price										Low Stock Price									
				2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	ALE	ALLETE	0.8	51.3	49	35.3	37.9	42.5	42.7	54.1	58	59.7	66.9	38.2	28.3	23.3	30	35.1	37.7	41.4	44.2	45.3	48.3
2	AEP	AMERICAN ELEC. PWR.	0.65	51.2	49.1	36.5	37.9	41.7	45.4	51.6	63.2	65.4	71.3	41.7	25.5	24	28.2	33.1	37	41.8	45.8	52.3	56.8
3	AVA	AVISTA CORP.	0.7	25.8	23.6	22.4	22.8	26.5	28	29.3	37.4	38.3	45.2	18.2	15.5	12.7	18.5	21.1	22.8	24.1	27.7	29.8	34.3
4	CNP	CENTERPOINT EN'RGY	0.85	20.2	17.3	14.9	17	21.5	21.8	25.7	25.8	23.7	25	14.7	8.5	8.7	5.5	15.1	18.1	19.3	21.1	16	16.4
5	CMS	CMS ENERGY CORP.	0.65	19.5	17.5	16.1	19.3	22.4	25	30	36.9	38.7	46.3	15	8.3	10	14.1	17	21.1	24.6	26	31.2	35
6	ED	CON. EDISON	0.5	52.9	49.3	46.3	51	62.7	66	64	68.9	72.3	81.9	43.1	34.1	32.6	41.5	48.6	53.6	54.2	52.2	56.9	63.5
7	D	DOMINION RES.	0.65	49.4	48.5	39.8	45.1	53.6	55.6	68	80.9	79.9	79	39.8	31.3	27.1	36.1	42.1	48.9	51.9	63.1	64.5	66.3
8	DTE	DTE ENERGY CO.	0.65	54.7	45.3	45	49.1	55.3	62.6	73.3	90.8	92.3	100.4	44	27.8	23.3	41.3	43.2	52.5	60.3	64.8	73.2	78
9	EIX	EDISON INTERNAT'L	0.6	60.3	55.7	36.7	39.4	41.6	48	54.2	68.7	69.6	78.7	42.8	26.7	23.1	30.4	32.6	39.6	44.3	44.7	55.2	58
10	EE	EL PASO ELECTRIC	0.75	28.2	25.5	21.1	28.7	35.7	35.3	39.1	42.2	41.3	48.8	20.8	15.2	11.6	18.7	26.7	29.2	31.8	33.4	33.8	37.2
11	ETR	ENTERGY CORP.	0.65	125	127.5	86.6	84.3	74.5	74.5	72.6	92	90.3	82.1	89.6	61.9	59.9	68.7	57.6	61.6	60.2	60.4	61.3	65.4
12	ES	EVERSOURCE ENERGY	0.65	33.6	31.6	26.5	32.2	36.5	40.9	45.7	56.7	56.8	60.4	26.2	17.2	19	24.7	30	33.5	38.6	41.3	44.6	50
13	EXC	EXELON CORP.	0.65	86.8	92.1	59	49.9	45.4	43.7	37.8	38.9	38.3	37.7	58.7	41.2	38.4	17	39.1	28.4	26.6	26.5	25.1	26.3
14	FE	FIRSTENERGY	0.65	75	84	53.6	47.8	46.5	51.1	46.8	40.8	41.7	36.6	57.8	41.2	35.3	33.6	36.1	40.4	31.3	30	28.9	29.3
15	FTS	FORTIS INC.	0.65	29.8	29.9	29.2	34.5	35.4	40.7	35.1	40.5	42.1	45.1	24.5	20.7	21.5	21.6	28.2	30.5	29.6	29.8	34.5	36
16	GXP	GREAT PLAINS EN'GY	0.75	33.4	29.3	20.5	19.9	22.1	22.8	24.9	29.5	30.3	32.7	26.9	15.6	10.2	16.6	16.3	19.5	20.4	23.8	24.1	25.8
17	HE	HAWAIIAN ELECTRIC	0.7	27.5	29.8	22.7	25	26.8	29.2	28.3	35	34.9	35	20.3	21	12.1	18.6	20.6	23.7	23.8	22.7	27	27.3
18	IDA	IDACORP, INC.	0.7	39.2	35.1	32.8	37.8	42.7	45.7	54.7	70.1	70.5	83.4	30.1	21.9	20.9	30	33.9	38.2	43.1	50.2	55.4	65
19	MGEE	MGE ENERGY INC.	0.75	24.8	24.3	25.5	29.1	31.9	37.4	40.5	48	48	66.9	19.6	18.6	18.2	21.4	24.7	28.7	33.4	35.7	36.5	44.8
20	NEE	NEXTERA ENERGY	0.65	72.8	73.8	60.6	56.3	61.2	72.2	89.8	110.8	112.6	132	53.7	33.8	41.5	45.3	49	58.6	69.8	84	93.7	102
21	NWE	NORTHWESTERN	0.65	36.7	29.7	26.8	30.6	36.6	38	47.2	58.7	59.7	63.8	24.5	16.5	18.5	23.8	27.4	33	35.1	42.6	48.4	52.2
22	OGE	OGE ENERGY CORP.	0.95	20.7	18.1	18.9	23.1	28.6	30.1	40	39.3	36.5	34.2	14.6	9.8	9.9	16.9	20.3	25.1	27.7	32.8	24.2	23.4
23	OTTR	OTTER TAIL CORP.	0.9	39.4	46.2	25.4	25.4	23.5	25.3	31.9	32.7	33.4	42.6	29	15	15.5	18.2	17.5	20.7	25.2	26.5	24.8	25.8
24	PCG	PG&E CORP.	0.65	52.2	45.7	45.8	48.6	48	47	48.5	55.2	60.2	65.4	42.6	26.7	34.5	34.9	36.8	39.4	39.9	39.4	47.3	50.7
25	PNW	PINNACLE WEST	0.65	51.7	42.9	38	42.7	48.9	54.7	61.9	71.1	73.3	82.8	36.8	26.3	22.3	32.3	37.3	45.9	51.5	51.2	56	62.5
26	POR	PORTLAND GENERAL	0.7	31.3	27.7	21.4	22.7	26	28.1	33.3	40.3	41	45.2	25.5	15.4	13.5	17.5	21.3	24.3	27.4	29	33	35.3
27	PPL	PPL CORPORATION	0.7	54.6	55.2	34.4	33.1	30.3	30.2	33.6	38.1	36.7	39.9	34.4	26.8	24.3	23.8	24.1	26.7	28.4	29.4	29.2	32.1
28	PEG	P.S. ENTERPRISE GP.	0.65	49.9	52.3	34.1	34.9	35.5	34.1	37	43.8	44.4	47.4	32.2	22.1	23.7	29	28	28.9	29.7	31.3	36.8	37.8
29	SCG	SCANA CORP.	0.65	45.5	44.1	38.6	42	45.5	50.3	54.4	63.4	65.6	76.4	32.9	27.8	26	34.2	34.6	43.3	44.7	45.6	49.9	59.5
30	SO	SOUTHERN COMPANY	0.55	39.3	40.6	37.6	38.6	46.7	48.6	48.7	51.3	53.2	54.6	33.2	29.8	26.5	30.8	35.7	41.8	40	40.3	41.4	46
31	WEC	WEC ENERGY GROUP	0.6	25.2	24.8	25.3	30.5	35.4	41.5	45	55.4	58	66.1	20.5	17.4	18.2	23.4	27	33.6	37	40.2	44.9	50.4
32	WR	WESTAR ENERGY	0.7	28.6	25.9	22.3	25.9	29	33	35	43.2	44	57.5	22.8	16	14.9	20.6	22.6	26.8	28.6	31.7	33.9	40
33	XEL	XCEL ENERGY	0.6	25	22.9	21.9	24.4	27.8	29.9	31.8	37.6	38.3	45.4	19.6	15.3	16	19.8	21.2	25.8	26.8	27.3	31.8	35.2

Southern California Edison Company
Comparable Earnings Analysis
Regulated Utility Reference Group - M/B Ratios

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
ALE	1.95	1.56	1.13	1.27	1.38	1.36	1.52	1.51	1.46	1.53
High	51.30	49.00	35.30	37.90	42.50	42.70	54.10	58.00	59.70	66.90
Low	38.20	28.30	23.30	30.00	35.10	37.70	41.40	44.20	45.30	48.30
Avg	44.75	38.65	29.30	33.95	38.80	40.20	47.75	51.10	52.50	57.60
bvEquity	23.01	24.74	25.89	26.84	28.02	29.63	31.46	33.75	36.07	37.62
AEP	1.90	1.45	1.12	1.18	1.28	1.34	1.45	1.62	1.66	1.78
High	51.20	49.10	36.50	37.90	41.70	45.40	51.60	63.20	65.40	71.30
Low	41.70	25.50	24.00	28.20	33.10	37.00	41.80	45.80	52.30	56.80
Avg	46.45	37.30	30.25	33.05	37.40	41.20	46.70	54.50	58.85	64.05
bvEquity	24.45	25.75	26.91	27.91	29.33	30.85	32.18	33.68	35.41	35.91
AVA	1.27	1.10	0.94	1.06	1.19	1.23	1.25	1.43	1.41	1.58
High	25.80	23.60	22.40	22.80	26.50	28.00	29.30	37.40	38.30	45.20
Low	18.20	15.50	12.70	18.50	21.10	22.80	24.10	27.70	29.80	34.30
Avg	22.00	19.55	17.55	20.65	23.80	25.40	26.70	32.55	34.05	39.75
bvEquity	17.37	17.79	18.74	19.44	20.01	20.68	21.34	22.73	24.19	25.11
CNP	3.30	2.24	1.87	1.58	2.10	2.00	2.23	2.27	2.13	2.57
High	20.20	17.30	14.90	17.00	21.50	21.80	25.70	25.80	23.70	25.00
Low	14.70	8.50	8.70	5.50	15.10	18.10	19.30	21.10	16.00	16.40
Avg	17.45	12.90	11.80	11.25	18.30	19.95	22.50	23.45	19.85	20.70
bvEquity	5.29	5.75	6.32	7.14	8.72	9.99	10.08	10.35	9.33	8.04
CMS	1.77	1.27	1.17	1.48	1.70	1.92	2.18	2.39	2.54	2.76
High	19.50	17.50	16.10	19.30	22.40	25.00	30.00	36.90	38.70	46.30
Low	15.00	8.30	10.00	14.10	17.00	21.10	24.60	26.00	31.20	35.00
Avg	17.25	12.90	13.05	16.70	19.70	23.05	27.30	31.45	34.95	40.65
bvEquity	9.75	10.17	11.15	11.31	11.56	12.01	12.54	13.16	13.78	14.72
ED	1.51	1.23	1.10	1.24	1.45	1.50	1.44	1.43	1.48	1.59
High	52.90	49.30	46.30	51.00	62.70	66.00	64.00	68.90	72.30	81.90
Low	43.10	34.10	32.60	41.50	48.60	53.60	54.20	52.20	56.90	63.50
Avg	48.00	41.70	39.45	46.25	55.65	59.80	59.10	60.55	64.60	72.70
bvEquity	31.84	34.01	35.95	37.20	38.49	39.79	41.17	42.38	43.75	45.72
D	2.56	2.38	1.86	2.07	2.35	2.72	3.13	3.62	3.52	3.27
High	49.40	48.50	39.80	45.10	53.60	55.60	68.00	80.90	79.90	79.00
Low	39.80	31.30	27.10	36.10	42.10	48.90	51.90	63.10	64.50	66.30
Avg	44.60	39.90	33.45	40.60	47.85	52.25	59.95	72.00	72.20	72.65
bvEquity	17.41	16.80	17.97	19.66	20.38	19.22	19.18	19.88	20.49	22.25
DTE	1.43	1.01	0.91	1.16	1.21	1.37	1.53	1.70	1.73	1.80
High	54.70	45.30	45.00	49.10	55.30	62.60	73.30	90.80	92.30	100.40
Low	44.00	27.80	23.30	41.30	43.20	52.50	60.30	64.80	73.20	78.00
Avg	49.35	36.55	34.15	45.20	49.25	57.55	66.80	77.80	82.75	89.20
bvEquity	34.44	36.32	37.37	38.82	40.54	42.10	43.76	45.89	47.97	49.55
EIX	2.08	1.49	1.01	1.11	1.17	1.46	1.66	1.77	1.82	1.91
High	60.30	55.70	36.70	39.40	41.60	48.00	54.20	68.70	69.60	78.70
Low	42.80	26.70	23.10	30.40	32.60	39.60	44.30	44.70	55.20	58.00
Avg	51.55	41.20	29.90	34.90	37.10	43.80	49.25	56.70	62.40	68.35
bvEquity	24.79	27.57	29.71	31.32	31.65	29.91	29.73	32.07	34.27	35.86

Southern California Edison Company
Comparable Earnings Analysis
Regulated Utility Reference Group - M/B Ratios

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
EE	1.79	1.35	1.02	1.34	1.64	1.63	1.61	1.58	1.52	1.67
High	28.20	25.50	21.10	28.70	35.70	35.30	39.10	42.20	41.30	48.80
Low	20.80	15.20	11.60	18.70	26.70	29.20	31.80	33.40	33.80	37.20
Avg	24.50	20.35	16.35	23.70	31.20	32.25	35.45	37.80	37.55	43.00
bvEquity	13.68	15.12	15.96	17.75	19.04	19.80	22.01	23.92	24.76	25.83
ETR	2.64	2.29	1.67	1.64	1.34	1.33	1.26	1.39	1.41	1.52
High	125.00	127.50	86.60	84.30	74.50	74.50	72.60	92.00	90.30	82.10
Low	89.60	61.90	59.90	68.70	57.60	61.60	60.20	60.40	61.30	65.40
Avg	107.30	94.70	73.25	76.50	66.05	68.05	66.40	76.20	75.80	73.75
bvEquity	40.58	41.39	43.81	46.54	49.17	51.27	52.87	54.92	53.86	48.51
ES	1.63	1.28	1.14	1.36	1.50	1.43	1.41	1.58	1.58	1.66
High	33.60	31.60	26.50	32.20	36.50	40.90	45.70	56.70	56.80	60.40
Low	26.20	17.20	19.00	24.70	30.00	33.50	38.60	41.30	44.60	50.00
Avg	29.90	24.40	22.75	28.45	33.25	37.20	42.15	49.00	50.70	55.20
bvEquity	18.40	19.02	19.88	20.99	22.13	26.03	29.95	30.98	32.06	33.22
EXC	4.81	4.15	2.71	1.69	2.00	1.54	1.25	1.24	1.17	1.14
High	86.80	92.10	59.00	49.90	45.40	43.70	37.80	38.90	38.30	37.70
Low	58.70	41.20	38.40	17.00	39.10	28.40	26.60	26.50	25.10	26.30
Avg	72.75	66.65	48.70	33.45	42.25	36.05	32.20	32.70	31.70	32.00
bvEquity	15.12	16.06	17.97	19.83	21.09	23.38	25.80	26.41	27.17	28.00
FE	2.30	2.21	1.61	1.45	1.38	1.45	1.27	1.18	1.20	1.52
High	75.00	84.00	53.60	47.80	46.50	51.10	46.80	40.80	41.70	36.60
Low	57.80	41.20	35.30	33.60	36.10	40.40	31.30	30.00	28.90	29.30
Avg	66.40	62.60	44.45	40.70	41.30	45.75	39.05	35.40	35.30	32.95
bvEquity	28.88	28.31	27.63	28.06	29.89	31.52	30.81	29.91	29.41	21.72
FTS	1.87	1.46	1.39	1.50	1.61	1.72	1.50	1.49	1.43	1.33
High	29.80	29.90	29.20	34.50	35.40	40.70	35.10	40.50	42.10	45.10
Low	24.50	20.70	21.50	21.60	28.20	30.50	29.60	29.80	34.50	36.00
Avg	27.15	25.30	25.35	28.05	31.80	35.60	32.35	35.15	38.30	40.55
bvEquity	14.49	17.36	18.29	18.76	19.74	20.69	21.62	23.65	26.77	30.48
GXP	1.73	1.13	0.73	0.87	0.89	0.97	1.02	1.16	1.16	1.21
High	33.40	29.30	20.50	19.90	22.10	22.80	24.90	29.50	30.30	32.70
Low	26.90	15.60	10.20	16.60	16.30	19.50	20.40	23.80	24.10	25.80
Avg	30.15	22.45	15.35	18.25	19.20	21.15	22.65	26.65	27.20	29.25
bvEquity	17.44	19.79	21.01	20.94	21.50	21.75	22.17	22.92	23.47	24.21
HE	1.66	1.66	1.13	1.40	1.50	1.64	1.56	1.67	1.75	1.69
High	27.50	29.80	22.70	25.00	26.80	29.20	28.30	35.00	34.90	35.00
Low	20.30	21.00	12.10	18.60	20.60	23.70	23.80	22.70	27.00	27.30
Avg	23.90	25.40	17.40	21.80	23.70	26.45	26.05	28.85	30.95	31.15
bvEquity	14.37	15.32	15.47	15.63	15.81	16.12	16.67	17.27	17.71	18.49
IDA	1.32	1.04	0.94	1.13	1.19	1.23	1.36	1.59	1.58	1.77
High	39.20	35.10	32.80	37.80	42.70	45.70	54.70	70.10	70.50	83.40
Low	30.10	21.90	20.90	30.00	33.90	38.20	43.10	50.20	55.40	65.00
Avg	34.65	28.50	26.85	33.90	38.30	41.95	48.90	60.15	62.95	74.20
bvEquity	26.28	27.28	28.47	30.09	32.10	34.13	35.96	37.85	39.87	41.81

Southern California Edison Company
Comparable Earnings Analysis
Regulated Utility Reference Group - M/B Ratios

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
MGEE	1.78	1.59	1.54	1.71	1.82	2.03	2.14	2.27	2.17	2.74
High	24.80	24.30	25.50	29.10	31.90	37.40	40.50	48.00	48.00	66.90
Low	19.60	18.60	18.20	21.40	24.70	28.70	33.40	35.70	36.50	44.80
Avg	22.20	21.45	21.85	25.25	28.30	33.05	36.95	41.85	42.25	55.85
bvEquity	12.46	13.46	14.20	14.81	15.52	16.30	17.26	18.42	19.47	20.41
NEE	2.49	1.96	1.70	1.55	1.57	1.77	2.01	2.25	2.20	2.32
High	72.80	73.80	60.60	56.30	61.20	72.20	89.80	110.80	112.60	132.00
Low	53.70	33.80	41.50	45.30	49.00	58.60	69.80	84.00	93.70	102.20
Avg	63.25	53.80	51.05	50.80	55.10	65.40	79.80	97.40	103.15	117.10
bvEquity	25.42	27.46	29.96	32.86	35.14	36.91	39.69	43.22	46.97	50.49
NWE	1.47	1.09	1.05	1.22	1.38	1.46	1.59	1.74	1.67	1.71
High	36.70	29.70	26.80	30.60	36.60	38.00	47.20	58.70	59.70	63.80
Low	24.50	16.50	18.50	23.80	27.40	33.00	35.10	42.60	48.40	52.20
Avg	30.60	23.10	22.65	27.20	32.00	35.50	41.15	50.65	54.05	58.00
bvEquity	20.89	21.19	21.56	22.25	23.16	24.39	25.85	29.05	32.36	33.95
OGE	1.97	1.45	1.39	1.80	1.97	2.04	2.31	2.28	1.84	1.70
High	20.70	18.10	18.90	23.10	28.60	30.10	40.00	39.30	36.50	34.20
Low	14.60	9.80	9.90	16.90	20.30	25.10	27.70	32.80	24.20	23.40
Avg	17.65	13.95	14.40	20.00	24.45	27.60	33.85	36.05	30.35	28.80
bvEquity	8.98	9.65	10.33	11.13	12.40	13.53	14.65	15.79	16.47	16.95
OTTR	2.00	1.67	1.08	1.20	1.23	1.52	1.96	1.96	1.86	2.07
High	39.40	46.20	25.40	25.40	23.50	25.30	31.90	32.70	33.40	42.60
Low	29.00	15.00	15.50	18.20	17.50	20.70	25.20	26.50	24.80	25.80
Avg	34.20	30.60	20.45	21.80	20.50	23.00	28.55	29.60	29.10	34.20
bvEquity	17.11	18.35	18.96	18.18	16.70	15.13	14.59	15.07	15.69	16.51
PCG	2.03	1.44	1.49	1.48	1.46	1.45	1.43	1.47	1.61	1.68
High	52.20	45.70	45.80	48.60	48.00	47.00	48.50	55.20	60.20	65.40
Low	42.60	26.70	34.50	34.90	36.80	39.40	39.90	39.40	47.30	50.70
Avg	47.40	36.20	40.15	41.75	42.40	43.20	44.20	47.30	53.75	58.05
bvEquity	23.31	25.08	26.93	28.22	28.95	29.85	30.88	32.25	33.39	34.54
PNW	1.27	1.00	0.90	1.13	1.25	1.41	1.53	1.58	1.60	1.72
High	51.70	42.90	38.00	42.70	48.90	54.70	61.90	71.10	73.30	82.80
Low	36.80	26.30	22.30	32.30	37.30	45.90	51.50	51.20	56.00	62.50
Avg	44.25	34.60	30.15	37.50	43.10	50.30	56.70	61.15	64.65	72.65
bvEquity	34.82	34.66	33.43	33.28	34.42	35.59	37.14	38.79	40.40	42.23
POR	1.40	1.01	0.83	0.97	1.09	1.17	1.31	1.45	1.48	1.55
High	31.30	27.70	21.40	22.70	26.00	28.10	33.30	40.30	41.00	45.20
Low	25.50	15.40	13.50	17.50	21.30	24.30	27.40	29.00	33.00	35.30
Avg	28.40	21.55	17.45	20.10	23.65	26.20	30.35	34.65	37.00	40.25
bvEquity	20.32	21.35	21.07	20.82	21.61	22.47	23.09	23.87	24.93	25.89
PPL	3.16	2.88	2.09	1.80	1.52	1.55	1.64	1.68	1.87	2.46
High	54.60	55.20	34.40	33.10	30.30	30.20	33.60	38.10	36.70	39.90
Low	34.40	26.80	24.30	23.80	24.10	26.70	28.40	29.40	29.20	32.10
Avg	44.50	41.00	29.35	28.45	27.20	28.45	31.00	33.75	32.95	36.00
bvEquity	14.09	14.22	14.06	15.78	17.85	18.37	18.90	20.13	17.60	14.64

Southern California Edison Company
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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
PEG	2.96	2.50	1.77	1.76	1.61	1.51	1.51	1.60	1.63	1.64
High	49.90	52.30	34.10	34.90	35.50	34.10	37.00	43.80	44.40	47.40
Low	32.20	22.10	23.70	29.00	28.00	28.90	29.70	31.30	36.80	37.80
Avg	41.05	37.20	28.90	31.95	31.75	31.50	33.35	37.55	40.60	42.60
bvEquity	13.85	14.86	16.37	18.21	19.67	20.81	22.13	23.52	24.98	25.94
SCG	1.58	1.40	1.21	1.34	1.36	1.52	1.54	1.60	1.58	1.74
High	45.50	44.10	38.60	42.00	45.50	50.30	54.40	63.40	65.60	76.40
Low	32.90	27.80	26.00	34.20	34.60	43.30	44.70	45.60	49.90	59.50
Avg	39.20	35.95	32.30	38.10	40.05	46.80	49.55	54.50	57.75	67.95
bvEquity	24.88	25.61	26.74	28.34	29.50	30.71	32.28	34.02	36.52	39.08
SO	2.30	2.11	1.82	1.86	2.08	2.18	2.09	2.11	2.12	2.11
High	39.30	40.60	37.60	38.60	46.70	48.60	48.70	51.30	53.20	54.60
Low	33.20	29.80	26.50	30.80	35.70	41.80	40.00	40.30	41.40	46.00
Avg	36.25	35.20	32.05	34.70	41.20	45.20	44.35	45.80	47.30	50.30
bvEquity	15.74	16.66	17.62	18.68	19.77	20.71	21.26	21.71	22.29	23.80
WEC	1.79	1.53	1.47	1.71	1.86	2.13	2.23	2.49	2.19	2.09
High	25.20	24.80	25.30	30.50	35.40	41.50	45.00	55.40	58.00	66.10
Low	20.50	17.40	18.20	23.40	27.00	33.60	37.00	40.20	44.90	50.40
Avg	22.85	21.10	21.75	26.95	31.20	37.55	41.00	47.80	51.45	58.25
bvEquity	12.80	13.76	14.77	15.76	16.73	17.63	18.39	19.17	23.51	27.86
WR	1.40	1.07	0.91	1.11	1.19	1.33	1.36	1.53	1.53	1.85
High	28.60	25.90	22.30	25.90	29.00	33.00	35.00	43.20	44.00	57.50
Low	22.80	16.00	14.90	20.60	22.60	26.80	28.60	31.70	33.90	40.00
Avg	25.70	20.95	18.60	23.25	25.80	29.90	31.80	37.45	38.95	48.75
bvEquity	18.38	19.66	20.39	20.92	21.64	22.46	23.39	24.45	25.45	26.36
XEL	1.54	1.27	1.21	1.35	1.43	1.56	1.57	1.65	1.71	1.89
High	25.00	22.90	21.90	24.40	27.80	29.90	31.80	37.60	38.30	45.40
Low	19.60	15.30	16.00	19.80	21.20	25.80	26.80	27.30	31.80	35.20
Avg	22.30	19.10	18.95	22.10	24.50	27.85	29.30	32.45	35.05	40.30
bvEquity	14.49	15.03	15.64	16.34	17.10	17.82	18.70	19.71	20.55	21.31

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Median	1.8	1.4	1.2	1.4	1.4	1.5	1.5	1.6	1.6	1.7

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies - Input Data

Index	Ticker Symbols	Company Name	Beta	Book Value per Share (Long)											Average Annual P/E Ratio									
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	MMM	3M COMPANY	0.9	13.56	16.56	14.24	17.96	22	22.19	25.58	26.39	20.64	19.21	17.26	15	14.6	14.1	14.5	14.5	14.1	17	19.1	20.6	20.6
2	APH	AMPHENOL CORP.	0.95	2.55	3.54	3.94	5.04	6.61	6.66	7.6	9.04	9.38	10.51	11.92	19.1	16.7	18.5	16	16.4	17	20.1	21.6	22.8	21.7
3	AAPL	APPLE INC.	0.9	1.67	2.38	3.38	4.42	7.45	11.78	17.98	19.63	19.02	21.39	24.03	26.3	30.4	19.2	15.2	12.4	12	12.3	13	12.8	12.6
4	T	AT&T INC.	0.75	29.76	19.09	16.35	17.34	18.94	17.85	16.61	17.5	16.76	19.96	20.06	14.2	15.4	12.1	11.7	13.4	14.5	14.2	13.8	12.6	13.8
5	ADP	AUTO. DATA PROC.	0.95	10.71	9.61	9.97	10.61	11.14	12.25	12.63	12.83	13.89	10.31	9.83	26	20.1	16	17.2	18.7	18.7	21.8	24.5	29	26
6	BLL	BALL CORP.	0.95	2.83	3.32	2.89	4.2	4.41	3.8	3.72	4.22	3.77	4.4	9.82	14.2	12.2	11.2	9.6	13.6	16	16.9	18.3	34.8	45.2
7	BAX	BAXTER INT'L	0.85	9.64	10.91	10.11	11.97	11.31	11.57	12.7	15.58	14.97	16.15	15.36	19.6	18.2	14.2	12.6	12.6	12.8	14.9	14.7	40.5	22.4
8	BDX	BECTON, D'SON.	0.8	15.63	17.89	20.3	21.69	23.65	22.48	21	26	26.32	34	35.79	19.5	19	13.7	14.9	14.5	14.1	15.6	18.1	19.5	18.4
9	BFB	BROWN-FORMAN `B'	0.85	3.4	3.81	4.03	4.3	4.74	4.85	3.81	4.76	4.56	3.95	3.57	19.7	17.8	16.1	17.9	21.4	24.1	24.7	28.4	28.8	27.6
10	CPB	CAMPBELL SOUP	0.7	4.4	3.42	3.7	2.02	2.76	3.4	2.88	3.9	5.16	4.45	4.95	19.7	16.6	14.6	14.1	13.7	13.4	16	17.1	17.1	19.3
11	CAH	CARDINAL HEALTH	0.95	20.94	20.04	21.7	24.24	14.8	16.66	18.2	17.56	19.01	19.07	20.41	20	15.8	17.4	14.6	14.3	13.8	13	18.5	22.6	19.1
12	CERN	CERNER CORP.	0.95	2.93	3.53	4.04	4.79	5.72	6.81	8.23	9.21	10.42	11.38	11.92	36.2	21.1	25.7	30	33.5	33.1	37.3	34.8	31.5	24.6
13	CHRW	C.H. ROBINSON	0.85	5.47	6.1	6.51	6.46	7.25	7.04	9.33	6.33	7.16	8.02	8.9	27.2	25.9	24.6	27	28.1	16.7	22.3	20.6	19.5	19.8
14	CHD	CHURCH & DWIGHT	0.7	3.3	4.08	4.75	5.68	6.57	7.17	7.43	8.28	7.88	7.78	7.79	19.9	19.8	15.8	16.6	18.4	21.2	22.3	23.1	26	26.5
15	CI	CIGNA CORPORATION	0.85	14.63	16.98	13.24	19.8	24.51	30.82	34.3	37.83	40.83	46.91	53.4	12.8	10.5	6.2	7.4	8.6	7.8	10.6	12.1	15.5	16.4
16	CTAS	CINTAS CORP.	0.95	12.8	13.66	14.67	15.49	16.58	16.74	16.91	18	18.74	17.3	17.68	18.9	15.7	13.8	17.9	16.6	14.9	16.6	19.4	21.4	21.5
17	KO	COCA-COLA	0.75	3.65	4.69	4.43	5.38	6.76	6.99	7.34	7.54	6.94	5.91	5.38	21	17.8	16.6	16.2	17.4	18.8	19.1	20	20.6	22.8
18	CMCSA	COMCAST CORP.	0.9	4.31	6.86	7.02	7.53	7.99	8.74	9.38	9.76	10.41	10.7	11.35	34.1	20.9	11.8	14.3	14.9	14	16.9	18.2	18.1	18.2
19	CAG	CONAGRA BRANDS	0.7	9.1	9.36	11.02	10.69	11.13	11.45	10.89	12.55	12.46	10.57	8.48	18.2	22.8	12	12.8	13.2	13.9	13.8	14.9	15.8	20.3
20	STZ	CONSTELLATION	0.85	14.54	12.8	8.71	11.59	12.14	13.77	15.07	25.35	28.92	32.89	35.41	15.9	11.2	8.5	9.5	8.7	13.6	18.4	20.3	23.6	23.3
21	COST	COSTCO WHOLESALE	0.8	19.78	19.73	21.25	22.98	24.98	27.64	28.59	24.8	28.11	24.24	27.61	21	23.1	19.5	19.9	22.1	21.9	23.4	25.1	26.7	29
22	BCR	BARD (C.R.), INC.	0.85	16.46	18.44	19.89	22.87	19.2	21.08	23.57	26.97	24.1	19.75	22.98	21.7	20.5	15.3	14.8	15	14.9	19.6	17.6	19.8	20.6
23	DE	DEERE & CO.	0.95	16.48	16.28	15.47	11.39	14.9	16.75	17.64	27.46	26.23	21.29	20.71	14.5	16.1	14	13.7	12.5	10.4	9.5	10.1	15.2	16.7
24	XRAY	DENTSPLY SIRONA	0.95	8.39	10.05	10.68	12.46	12.97	13.04	15.52	17.81	16.48	16.69	35.3	22.5	19.6	16.5	17.2	17.8	17.2	18.4	19.1	20.6	21.7
25	EW	EDWARDS LIFESCI.	0.85	3.25	3.69	3.93	5.1	5.69	5.86	6.47	7.13	10.16	11.62	12.38	23.1	20.9	21.8	30.8	39.3	32.5	23.6	26.3	31	34.2
26	LLY	Lilly (Eli)	0.75	9.7	12.05	5.93	8.29	10.77	11.69	12.92	15.8	13.86	13.18	12.72	15.7	11.4	7.8	7.4	8.4	12.9	12.7	22.2	22.9	21.7
27	EFX	EQUIFAX, INC.	0.95	6.72	10.79	10.39	12.8	13.93	14.4	16.27	19.18	18.7	19.47	22.21	17.4	13.2	11.5	13.7	14	15.6	17	19	21.9	21.8
28	EXPD	EXPEDITORS INT'L	0.95	5.02	5.76	6.45	7.32	8.21	9.45	9.82	10.29	9.75	9.29	10.26	36.9	28.7	28.7	26.3	26.6	25.2	24.3	22.1	19.7	20.9
29	ESRX	EXPRESS SCRIPTS.	0.95	2.07	1.38	2.18	6.46	6.83	5.1	28.58	28.23	27.63	25.67	26.81	21.8	21.1	21.7	22	20.2	31.1	26.7	27.9	24.2	16.6
30	XOM	EXXON MOBIL	0.95	19.87	22.62	22.7	23.39	29.49	32.61	36.84	40.14	41.51	41.1	40.34	11.4	9.5	17.8	10.5	9.5	10.7	12.3	12.8	21.5	45.8
31	FISV	FISERV, INC.	0.9	7.09	7.47	8.32	9.88	10.99	11.75	12.8	13.97	13.71	11.81	11.79	19.9	14.2	11.8	12.6	13	13.7	15.8	18.4	21.7	22.9
32	FLIR	FLIR SYSTEMS, INC.	0.9	3.03	4.56	5.94	7.88	9.56	10.19	10.97	11.46	11.53	12.01	12.31	26.5	26.1	17.2	18.3	19	14.9	22.7	24	19.2	21
33	FL	FOOT LOCKER	0.85	14.74	14.82	12.42	12.44	13.1	13.92	15.83	17.14	17.87	18.64	20.61	42.7	18.4	19.6	13.7	12.1	12.6	12.3	14	16.9	13.4
34	GD	GEN'L. DYNAMICS	0.95	24.22	29.13	26	32.21	35.79	37.12	32.2	41.03	35.66	34.51	36.29	16	12.9	9.2	9.9	9.9	10.4	11.3	15.2	15.5	14.8
35	GIS	GENERAL MILLS	0.75	8.11	7.82	9.21	7.89	8.23	9.87	9.9	10.41	10.67	8.35	8.26	17.6	16.5	15.2	14.3	14.7	15.1	15.7	17.8	18.6	20
36	GPC	GENUINE PARTS	0.95	14.96	16.36	14.58	16.49	17.72	17.88	19.43	21.84	21.63	20.97	21.52	16.4	13.9	13.8	14.4	15.1	15.2	18.6	19.3	19.5	20.8
37	HAS	HASBRO, INC.	0.9	9.57	9.54	9.99	11.63	11.76	11.02	11.69	12.84	11.77	13.33	14.96	14.2	15.9	10.7	15	14.8	12.8	16.3	17.1	20	18.1
38	HSIC	SCHEIN (HENRY) INC.	0.95	16.62	19.87	21.62	23.85	26.23	27.05	29.75	32.53	33.49	35	35.18	21.6	17.7	14.6	15.9	16.9	17.6	20.2	22	25.2	26.4
39	HSY	HERSHEY CO. (THE)	0.7	2.97	2.61	1.4	3.16	3.97	3.76	4.63	7.17	6.59	4.6	3.7	23.2	19.5	16.9	17.9	19.8	20.9	24.2	24.5	23	21.9

Southern California Edison Company
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Unregulated Companies - Input Data

Index	Ticker Symbols	Company Name	Beta	Book Value per Share (Long)											Average Annual P/E Ratio									
				2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
40	HD	HOME DEPOT	0.95	12.71	10.48	10.48	11.42	11.64	11.64	11.98	9.07	7.13	5.04	3.6	15.4	14.3	15.3	15.6	15	17.9	20.2	19.1	22.1	20.3
41	HRL	HORMEL FOODS	0.75	3.28	3.47	3.73	3.97	4.52	5.04	5.37	6.29	6.85	7.57	8.42	17.3	18.2	13	13.7	15.7	15.6	19.8	21.3	21.6	23.4
42	HUM	HUMANA INC.	0.8	18.32	23.7	26.4	33.93	41.08	49.16	55.87	60.48	64.48	69.76	71.56	13.3	11	5.5	7.7	8.8	10.2	9.8	16.3	22.7	18.7
43	IBM	INT'L BUS. MACH.	0.9	18.92	20.55	10.06	17.43	18.87	17.4	16.88	21.62	11.98	14.77	19.29	14.8	12.3	10.9	11.4	13.1	13.7	13	11.7	11.4	12.1
44	IFF	International Flavors & Fragra	0.95	10.12	7.62	7.29	9.71	12.45	13.65	15.3	17.98	18.8	19.87	20.53	18.4	14.3	12.7	14.4	15.7	14.8	17.7	19.1	21.6	22.6
45	SJM	SMUCKER (J.M.) CO.	0.7	31.62	32.95	41.71	44.71	46.35	46.82	48.35	49.46	59.27	60.26	60.39	16.9	12	12.5	13.2	16.2	16	18.3	19.6	20.1	21
46	JNJ	JOHNSON & JOHNSON	0.8	13.59	15.25	15.35	18.37	20.66	20.95	23.33	26.25	25.06	25.83	26.02	15.4	14.3	12.5	13.1	12.7	13.1	15.6	17.7	18.2	19.1
47	K	KELLOGG CO.	0.75	5.2	6.48	3.79	5.96	5.9	4.93	6.7	9.77	7.83	6.08	5.44	19	17	14.5	15.7	15.8	15.3	16.5	16.5	18.7	20.5
48	KR	THE KROGER CO.	0.85	3.49	3.71	3.99	3.76	4.27	3.55	4.09	5.3	5.56	7.05	7.25	16.4	14.1	12.5	12.4	11.8	9.1	12.9	14.5	18.2	16.4
49	LH	LAB. CORP. AMER.	0.9	16.18	15.54	15.59	20.12	24.66	25.6	29.06	29.07	33.34	48.81	53.61	18	15.4	13.4	13.9	14	13	13.8	14.8	15.3	14.3
50	MAT	MATTEL, INC.	0.85	6.33	6.38	5.91	6.99	7.53	7.75	8.96	9.58	8.72	7.75	7.03	15.9	17.5	11.2	12.1	12.1	13.5	16.7	24.3	23.3	34
51	MKC	McCORMICK	0.8	7.17	8.49	8.11	10.13	10.99	12.16	12.81	14.85	14.11	13.12	12.98	19.4	17.2	13.7	14.8	17.1	18.7	22	20.6	22.5	25.1
52	MDT	MEDTRONIC, PLC.	0.95	9.6	10.25	11.42	13.33	14.92	16.5	18.38	19.46	37.44	37.21	38.3	19.4	14.1	12.3	11	10.7	11.3	14.6	15.5	14.6	15
53	MRK	MERCK & CO.	0.85	8.1	8.37	8.9	19	17.64	17.93	17.52	17	17.14	16.06	14.58	34.1	10.2	9.1	10.5	9.1	10.8	13.3	16.4	15.8	15.2
54	TAP	MOLSON COORS	0.95	32.85	39.55	32.54	38.04	41.75	40.79	42.15	45.06	40.74	38.17	50.89	16.8	18	11.3	12.6	12.2	17.5	16.3	24.3	40.8	32.7
55	MON	MONSANTO COMPANY	0.95	12.01	13.75	17.09	18.44	18.61	21.57	22.13	23.74	16.35	14.94	10.36	28	32.3	18.7	28.5	22.6	20.7	21.6	21.7	20	32.5
56	NKE	NIKE, INC. `B'	0.9	3.03	3.49	3.98	4.48	5.04	5.18	5.67	6.24	6.22	7.41	7.29	16.5	17.8	15.3	16.4	18.2	20.4	19.4	24.2	24.4	27.5
57	NOC	NORTHROP GRUMMAN	0.9	48.03	52.35	36.45	41.34	46.59	40.71	40.12	49	36.47	30.46	30.04	15.2	12.4	9.9	10.5	8.3	8.2	10.4	12.9	16.1	17.4
58	PDCO	PATTERSON COS.	0.9	9.89	8.21	9.72	11.68	12.89	12.47	13.21	14.16	14.66	14.55	13.35	22.7	21.2	14.8	14.9	15.7	16.2	17.2	19.4	19.8	24.2
59	PAYX	PAYCHEX, INC.	0.95	4.35	5.11	3.32	3.72	3.88	4.13	4.43	4.85	4.9	4.94	5.3	28.4	24.6	19.2	22.2	20.7	19.6	21.4	24.1	24.8	24
60	PEP	PEPSICO, INC.	0.8	9.36	10.71	7.77	11.12	13.56	13.34	14.41	15.85	11.69	8.28	7.81	20.5	20.5	14.7	16.5	16.4	17.4	18.4	20.8	20.7	21.4
61	PRGO	PERRIGO CO. PLC	0.8	6.9	8.08	10.01	10	11.85	16.5	19.82	24.83	64.97	72.88	41.55	20.7	18.9	15.9	15.4	19.3	22.4	24.2	22.2	22.6	20.7
62	PFE	PFIZER INC.	0.85	9.98	9.6	8.52	11.15	10.95	10.84	11.16	11.92	11.33	10.48	9.81	11.5	16.4	12.8	16.3	17.6	18.4	17.6	21.5	30.3	28.1
63	PG	PROCTER & GAMBLE	0.7	19.33	20.87	22.46	21.18	21.2	24.14	22.87	24.64	25.4	22.83	21.34	20.5	18.6	16.4	17	16	16.7	17.8	19	20.9	21.4
64	QCOM	QUALCOMM INC.	0.9	8.12	9.62	10.84	12.17	12.94	16.05	19.66	21.42	23.47	20.62	21.53	19.9	19.5	21	16.5	16.4	15.9	14.2	14.3	14.5	12.1
65	DGX	QUEST DIAGNOST.	0.95	15.57	17.13	18.92	22.3	23.57	23.46	26.29	27.42	29.87	32.76	33.78	18.6	15.1	13.7	13	12.2	13.6	14.8	14.5	14.8	15.2
66	RTN	RAYTHEON	0.8	24.9	29.43	22.71	25.64	27.17	24.13	24.47	35.09	31	33.87	34.35	17.3	14.8	9.4	10.6	8.9	9.5	11.7	14	16.2	18
67	RSG	REPUBLIC SERVICES	0.8	7.29	7.03	19.24	19.87	20.46	20.77	21.34	21.94	21.97	22.5	22.66	18.5	15.2	16	17.2	14.9	15.7	16.9	18.7	20.1	22.3
68	RMD	RESMED INC.	0.9	4.88	6	7.12	7.41	8.51	11.41	11.32	11.34	12.54	11.3	12.05	33.4	29.5	20.2	21.8	22.3	17.2	20	20.3	23.4	22.7
69	ROST	ROSS STORES, INC.	0.85	1.63	1.81	1.96	2.35	2.82	3.3	4.02	4.7	5.49	6.14	7.01	15.5	14.1	11.6	12	14.1	17.2	17.4	17	20.3	21.4
70	SBUX	STARBUCKS CORP.	0.95	1.47	1.55	1.69	2.05	2.48	2.95	3.41	4.11	3.52	3.92	4.03	36.3	26.4	16	18.7	22.8	27.5	26.5	27.9	30.2	30.4
71	SRCL	STERICYCLE INC.	0.9	7.06	8.17	7.86	10.12	12.67	14.49	17.93	20.47	22.32	23.37	24.18	33.1	32.2	24.2	25.1	29.8	27	29.2	27.8	30.5	21.6
72	SYK	STRYKER CORP.	0.9	10.27	13.09	13.64	16.57	18.34	20.16	22.59	23.94	22.69	22.82	25.47	27.9	21.8	15.1	15.7	14.8	15.8	25.9	35.2	25.2	25.4
73	SYY	SYSCO CORP.	0.75	4.93	5.36	5.67	5.85	6.51	7.94	8	8.86	8.99	8.85	6.22	20.8	17.2	14.3	13.8	15	15.1	19.2	22.2	20.8	20.3
74	TGT	TARGET CORP.	0.8	18.18	18.7	18.22	20.61	22	23.64	25.66	25.64	21.86	21.52	19.69	18	16.2	12.8	13.9	11.9	13.7	20.7	14.7	16.6	14.6
75	TJX	TJX COMPANIES	0.85	2.52	2.49	2.59	3.53	3.98	4.3	5.06	6	6.23	6.49	6.98	14.8	14.6	11.5	13.2	14	16.5	18.9	19	20.8	21.6
76	UNH	UNITEDHEALTH GRP.	0.85	15.47	16.01	17.3	20.58	23.78	26.44	30.6	32.54	34.02	35.39	40.1	15.3	10.9	8.1	8	9.8	10.4	11.9	14.7	19.4	16.8
77	VAR	VARIAN MEDICAL	0.95	6.15	6.56	8.18	10.47	10.81	11.07	13.8	16.09	16.17	17.45	18.58	25	22.3	13.9	17.2	19.1	16.6	17.5	21.1	21.3	19.8
78	VZ	VERIZON	0.75	16.68	17.62	14.68	14.67	13.64	12.69	11.6	9.38	2.96	4.03	5.53	17.6	13.7	12.7	13.8	17.1	18.1	12.2	14.5	11.8	13.3
79	WBA	WALGREENS BOOTS	0.9	10.04	11.2	13.01	14.54	15.34	16.7	19.32	20.55	21.63	28.32	27.96	22.2	17.1	13.9	15.9	14.8	13.2	16.3	21.8	20.2	18
80	WMT	WAL-MART STORES	0.65	14.91	16.26	16.63	18.69	19.49	20.86	23.04	23.59	25.22	25.47	25.52	14.9	16.2	13.9	13.1	12.4	13.5	14.9	15.4	15.5	16.2
81	WM	WASTE MANAGEMENT	0.75	11.66	11.58	12.03	12.93	13.18	13.18	13.69	12.29	12.79	11.95	12.06	17.7	15.4	14.6	16.3	16.4	16.2	18.9	18.2	20.4	21.3
82	WAT	WATERS CORP.	0.95	3.57	5.8	6.75	9.02	11.64	13.5	16.42	20.79	22.79	25.27	28.77	24.3	17.7	14.4	16.7	17.9	16	18.8	21.1	22.3	21.7
83	WFM	WHOLE FOODS MKT.	0.9	5.3	5.24	5.37	5.79	6.9	8.36	10.25	10.41	10.58	10.8	10.13	35.6	40.4	20.4	23.9	29.3	32.6	33.1	31.2	27.4	20.1
84	GWW	GRAINGER (W.W.)	0.9	25.9	26.4	27.2	30.82	32.97	38.94	44.87	48.36	47.59	36.54	30.58	17.2	13.4	16	16.4	16.8	21.1	21.5	20.3	19	19.1
															Median									
															19.3	17.1	14.3	14.8	15.0	15.6	17.5	19.1	20.6	21.0

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies - Input Data

Index	Ticker Symbols	Company Name	Beta	High Stock Price										Low Stock Price									
				2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
1	MMM	3M COMPANY	0.9	97	84.8	84.3	91.5	98.2	95.5	140.4	168.2	170.5	182.3	72.9	50	40.9	68	68.6	82	94	123.6	134	134.6
2	APH	AMPHENOL CORP.	0.95	23.6	26.1	23.6	27	29.6	32.6	44.7	55.7	60.5	69.2	15.3	9.2	10.8	18.9	19.5	22.5	32.9	42.1	47.4	44.5
3	AAPL	APPLE INC.	0.9	29	28.6	30.6	46.7	61	100.7	82.2	119.8	134.5	118.7	11.7	11.3	11.2	27.2	44.4	58.4	55	70.5	92	89.5
4	T	AT&T INC.	0.75	43	41.9	29.5	29.6	31.9	38.6	39	37.5	36.4	43.9	32.7	20.9	21.4	23.8	27.2	29	32.8	31.7	31	33.4
5	ADP	AUTO. DATA PROC.	0.95	51.5	46	44.5	47.2	55.1	60	83.8	86.5	90.7	103.9	43.9	30.8	32	26.5	44.7	50.9	57.8	70.5	64.3	76.6
6	BLL	BALL CORP.	0.95	14	14	13.1	17.4	20.3	22.7	26	35.2	38.6	41.1	10.9	6.8	9.1	11.7	14.8	17.8	20.8	23.9	29	31.2
7	BAX	BAXTER INT'L	0.85	61.1	71.5	61	61.9	62.5	68.9	74.6	77.3	74	50.2	46.1	47.4	45.5	40.3	47.6	49	62.8	66.3	32.2	34.1
8	BDX	BECTON, D'SON.	0.8	85.9	93.2	80	85.5	89.8	80.6	110.9	142.6	157.5	181.8	69.3	58.1	60.4	66.5	69.6	71.6	78.7	105.2	128.9	129.5
9	BFB	BROWN-FORMAN `B'	0.85	21.3	21	18.5	24.3	27.3	35.5	38.4	49	55.5	51.7	16.8	13.5	11.7	16.3	20.7	25.7	30.5	36.7	43.4	43.8
10	CPB	CAMPBELL SOUP	0.7	42.7	40.8	35.8	37.6	35.7	37.2	48.8	46.7	55.1	67.9	34.2	27.3	24.6	32.2	29.7	31.2	34.8	39.6	42.9	50.5
11	CAH	CARDINAL HEALTH	0.95	76.1	62.3	39.9	39.3	47.1	44.5	67.8	83.4	91.9	90	56.4	27.8	24.9	29.7	37.5	36.9	41.1	63.1	74.8	62.7
12	CERN	CERNER CORP.	0.95	16.5	15	21.5	24.4	37.2	44.2	59.4	66.4	75.7	67.5	11	7.6	8.3	18	23	29.7	39.4	48.4	55.8	47
13	CHRW	C.H. ROBINSON	0.85	58.2	67.4	61.7	81	82.6	71.8	67.9	77.5	76.2	77.9	42.1	36.5	37.4	51.2	62.3	50.8	53.7	50.2	59.7	60.3
14	CHD	CHURCH & DWIGHT	0.7	14.3	16.4	15.6	17.8	23.2	29.6	33.5	40.5	45.4	53.7	10.6	11.9	11.4	14.8	16.9	22.1	26.9	30.5	38.7	38.4
15	CI	CIGNA CORPORATION	0.85	57.6	57	38.1	39.3	52.9	54.5	88.6	105.7	170.7	149	42.3	8	12.7	29.1	36.8	39	53.9	73.5	100.7	115
16	CTAS	CINTAS CORP.	0.95	42.9	33.9	30.8	29.7	35.3	45.6	59.7	80.4	94.3	122.2	31.1	19.5	18.1	23.1	26.4	35.2	41.2	55.3	75.9	80
17	KO	COCA-COLA	0.75	32.2	32.8	29.7	32.9	35.9	40.7	43.4	45	43.9	47.1	22.8	20.1	18.7	24.7	30.6	33.3	36.5	36.9	36.6	39.9
18	CMCSA	COMCAST CORP.	0.9	15.1	11.4	9	11.2	13.6	19.1	26	29.7	32.5	35.7	8.7	6.3	5.6	7.6	9.6	12.1	18.6	23.9	25	26.2
19	CAG	CONAGRA BRANDS	0.7	27.7	24.9	23.7	26.3	26.7	31.1	37.3	37.5	45.5	48.9	22.8	13.5	14	21	22.2	23.6	29.8	28.1	33.4	33.6
20	STZ	CONSTELLATION	0.85	29.2	23.8	17.6	22.5	23.2	37	71.6	100.8	144.9	173.5	18.8	10.7	10.7	14.6	16.4	18.5	28.4	68.5	96.5	130.2
21	COST	COSTCO WHOLESALE	0.8	72.7	75.2	61.3	73.2	88.7	106	126.1	146.8	169.7	169.6	51.5	43.9	38.2	53.4	69.5	78.8	98.9	109.5	117	138.6
22	BCR	BARD (C.R.), INC.	0.85	95.3	101.6	88.4	95.7	113.8	108.3	141	174.5	202.5	239.4	76.6	70	68.9	75.2	80.8	84.4	97.1	125	163.1	172.2
23	DE	DEERE & CO.	0.95	93.7	94.9	56.9	84.9	99.8	89.7	95.6	94.9	98.2	104.8	45.1	28.5	24.5	48.3	59.9	69.5	79.5	78.9	71.9	70.2
24	XRAY	DENTSPLY SIRONA	0.95	47.8	47.1	36.8	38.2	40.4	41.4	51	56.3	63.4	65.8	29.4	22.8	21.8	27.8	28.3	34.8	39.4	43	49.4	53.4
25	EW	EDWARDS LIFESCI.	0.85	13.2	16.7	22.1	42.7	45.9	55.4	47.5	67.1	83.4	121.8	11.4	10.4	13.2	21.2	30.8	33.9	30.3	31.5	61.4	72.2
26	LLY	Lilly (Eli)	0.75	61	57.5	40.8	38.1	41.9	54	58.4	75.1	92.9	85.4	49.1	28.6	27.2	32	33.5	38.3	47.5	50.5	68.3	64.2
27	EFX	EQUIFAX, INC.	0.95	46.3	39.9	31.6	36.6	39.9	55.5	69.6	82.6	114.5	137	35.2	19.4	19.6	27.6	28.6	37.9	52.8	64.8	79.6	91.7
28	EXPD	EXPEDITORS INT'L	0.95	54.5	49.9	38.1	57.2	56.2	47.5	46.9	47.2	51.8	56.4	38.3	24	23.9	32.4	38.3	34.2	34.8	38.1	42.2	40.4
29	ESRX	EXPRESS SCRIPTS.	0.95	37.2	39.6	44.9	55.7	60.9	66.1	70.8	86.3	94.6	87.9	16.2	24.2	21.4	37.8	34.5	45.7	53.1	64.6	68.1	64.5
30	XOM	EXXON MOBIL	0.95	95.3	96.1	82.7	73.7	88.2	93.7	101.7	104.8	93.4	95.6	69	56.5	61.9	55.9	67	77.1	84.8	86.2	66.6	71.6
31	FISV	FISERV, INC.	0.9	29.9	28.4	25.5	30.3	32.7	40.6	59.3	73.3	97.8	111.5	22.1	13.9	14.7	22.4	24.4	28.8	39.5	53.7	69.1	85.6
32	FLIR	FLIR SYSTEMS, INC.	0.9	36.4	45.5	33.3	33.3	37.3	27.1	33.8	37.4	34.5	37.2	14.8	23.7	18.8	24	21.9	18	22.9	28.3	25.1	26.5
33	FL	FOOT LOCKER	0.85	24.8	18.2	13	20	25.5	37.7	41.6	59.2	77.3	79.4	11.8	3.7	7.1	11.1	16.7	23.5	31.1	36.7	51.1	50.9
34	GD	GEN'L. DYNAMICS	0.95	94.6	95.1	70.8	79	78.3	74.5	95.8	146.1	153.8	180.1	70.6	47.8	35.3	55.5	53.9	61.1	64.5	93.9	130.9	121.6
35	GIS	GENERAL MILLS	0.75	30.8	36	36	39	40.8	41.9	53.1	55.6	59.9	72.9	27.1	25.5	23.2	33.1	34.5	36.8	40.4	46.7	47.4	53.5
36	GPC	GENUINE PARTS	0.95	51.7	46.3	39.8	51.6	62.2	66.9	85.4	109	108.1	106	46	29.9	24.9	36.9	46.1	55.6	64.4	76.5	78.8	76.5
37	HAS	HASBRO, INC.	0.9	33.5	41.7	32.6	50.2	48.4	40	55.2	59.4	84.4	88.5	25.3	21.6	21.1	30.2	31.4	31.7	35	47.5	51.4	65.5
38	HSIC	SCHEIN (HENRY) INC.	0.95	63.4	63.6	56.9	62.6	75	82.9	116.1	139.1	161.6	183	45.8	32.1	33.6	51	58.5	64.7	81.6	109.3	126.2	142.6
39	HSY	HERSHEY CO. (THE)	0.7	56.8	44.3	42.3	52.1	62.3	74.7	101.4	108.7	111.4	117.8	38.2	32.1	30.3	35.8	46.2	59.3	72.5	87.9	82.4	82.4

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies - Input Data

Index	Ticker Symbols	Company Name	Beta	High Stock Price 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Low Stock Price 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
40	HD	HOME DEPOT	0.95	42	31.1	29.4	37	42.5	65.9	82.5	106	135.5	139	25.6	17	17.5	26.6	28.1	41.9	62.4	74	92.2	109.6
41	HRL	HORMEL FOODS	0.75	10.5	10.7	10.1	13.1	15.3	15.8	23.1	27.7	40.4	45.7	7.5	6.2	7.3	9.4	12.3	13.6	15.7	21.4	25.1	33.2
42	HUM	HUMANA INC.	0.8	81.5	88.1	46.2	61.3	90.9	96.5	105.8	151.5	219.8	217.8	51	22.3	18.6	43.1	54.6	59.9	65.9	91	137.5	150
43	IBM	INT'L BUS. MACH.	0.9	122	130.9	132.9	147.5	194.9	211.8	215.9	199.2	176.3	170	88.8	69.5	81.8	116	146.6	177.3	172.6	150.5	131.6	116.9
44	IFF	International Flavors & Fragra	0.95	54.8	48	42.6	56.1	66.3	67.8	90.3	105.8	123.1	143.6	45.7	24.7	25	39.3	51.2	52.1	67.5	82.9	97.6	97.2
45	SJM	SMUCKER (J.M.) CO.	0.7	64.3	56.7	62.7	66.3	80.3	89.4	114.7	107.7	125.3	157.3	46.6	37.2	34.1	53.3	61.2	70.5	86.5	87.1	97.3	117.4
46	JNJ	JOHNSON & JOHNSON	0.8	68.8	72.8	65.4	66.2	68.1	72.7	96	109.5	106.5	126.1	59.7	52.1	46.3	56.9	57.5	61.7	70.3	86.1	81.8	94.3
47	K	KELLOGG CO.	0.75	56.9	58.5	54.1	56	57.7	57.2	68	69.5	73.7	87.2	48.7	40.3	35.6	47.3	48.1	46.3	56	55.7	61.1	68.7
48	KR	THE KROGER CO.	0.85	16	15.5	13.5	12.1	12.9	13.6	21.9	32.5	42.8	42.4	11.5	11.1	9.7	9.5	10.5	10.5	12.6	17.6	27.3	28.7
49	LH	LAB. CORP. AMER.	0.9	82.3	80.8	76.7	89.5	100.9	95.3	108	109.8	131.2	141.3	65.1	52.9	53.3	69.5	74.6	81.6	85.8	87.3	105.8	97.8
50	MAT	MATTEL, INC.	0.85	29.7	22	21	26.7	29.4	38	48.5	47.7	31.2	34.8	18.8	10.9	10.4	19.1	22.7	27.7	35.5	28.7	19.4	23.8
51	MKC	McCORMICK	0.8	39.7	42.1	36.8	47.8	51.3	66.4	75.3	77.1	87.5	107.8	33.9	28.2	28.1	35.4	43.4	49.9	60.8	62.8	70.7	78.4
52	MDT	MEDTRONIC, PLC.	0.95	58	57	44.9	46.7	43.3	44.8	58.8	75.7	79.5	89.3	44.9	28.3	24.1	30.8	30.2	35.7	41.2	53.3	55.5	71
53	MRK	MERCK & CO.	0.85	61.6	61.2	38.4	41.6	37.9	48	50.4	62.2	63.6	65.5	42.3	22.8	20	30.7	29.5	36.9	40.8	49.3	45.7	48
54	TAP	MOLSON COORS	0.95	57.7	59.5	51.3	51.1	50.4	46.3	56.5	77.9	95.7	112.2	37.6	35	30.8	38.4	38	38	41.3	50.9	63.9	80.8
55	MON	MONSANTO COMPANY	0.95	116	145.8	93.4	87.1	78.7	94.8	116.8	128.8	126	114.3	49.1	63.5	66.6	44.6	58.9	69.7	94	104.1	81.2	83.7
56	NKE	NIKE, INC. `B'	0.9	17	17.7	16.7	23.1	24.6	28.7	40.1	49.9	68.2	65.4	11.9	10.7	9.6	15.2	17.4	21.3	25.7	34.9	45.3	49
57	NOC	NORTHROP GRUMMAN	0.9	85.2	83.4	57.3	69.8	72.5	71.3	116.2	153.2	194	253.8	66.2	34	33.8	53.5	49.2	56.6	64.2	109.2	141.6	175
58	PDCO	PATTERSON COS.	0.9	40.1	37.8	28.3	32.8	36.9	36.4	44.4	49.5	53.1	50.4	28.3	15.8	16.1	24.1	26.2	29	34.3	37	42.6	36.5
59	PAYX	PAYCHEX, INC.	0.95	47.1	37.5	32.9	32.8	33.9	34.7	45.9	48.2	54.8	62.2	36	23.2	20.3	24.7	25.1	29.1	31.5	39.8	41.6	45.8
60	PEP	PEPSICO, INC.	0.8	79	79.8	64.5	68.1	71.9	73.7	87.1	100.7	103.4	110.9	61.9	49.7	43.8	58.8	58.5	62.2	68.6	77	76.5	93.2
61	PRGO	PERRIGO CO. PLC	0.8	36.9	43.1	40.9	68.4	104.7	120.8	157.5	171.6	215.7	152.4	16.1	27.7	18.5	37.5	62.3	90.2	98.8	125.4	140.4	79.7
62	PFE	PFIZER INC.	0.85	27.7	24.2	19	20.4	21.9	26.1	32.5	33.1	36.5	37.4	22.2	14.3	11.6	14	16.6	20.8	25.3	27.5	28.5	28.3
63	PG	PROCTER & GAMBLE	0.7	75.2	73.8	63.5	65.4	67.7	71	85.8	93.9	91.8	90.3	60.4	54.9	43.9	39.4	57.6	59.1	68.4	75.3	65	74.5
64	QCOM	QUALCOMM INC.	0.9	47.7	56.9	48.7	50.3	59.8	68.9	74.3	82	75.3	71.6	35.2	28.2	32.6	31.6	46	53.1	59	67.7	45.9	42.2
65	DGX	QUEST DIAGNOST.	0.95	58.6	59.9	62.8	61.7	61.2	64.9	64.1	68.5	89	93.6	48	38.7	42.4	40.8	45.1	53.3	52.5	50.5	60.1	59.7
66	RTN	RAYTHEON	0.8	65.9	67.5	53.8	60.1	53.1	59.3	91.4	111.5	130	152.6	51	41.8	33.2	42.7	38.3	47.5	52.2	87.6	95.3	115.7
67	RSG	REPUBLIC SERVICES	0.8	35	36.5	29.8	32.9	33.1	31.3	35.6	41.1	45.3	58	26.2	18.3	15	25.2	24.7	25.2	29.3	31.4	38.9	41.8
68	RMD	RESMED INC.	0.9	28.1	26.2	26.7	35.9	35.4	42.9	57.3	57.6	75.3	70.9	19.2	14.5	15.7	25	23.4	24.4	42	41.5	49	50.8
69	ROST	ROSS STORES, INC.	0.85	8.8	10.4	12.6	16.6	24.6	35.4	41	48.1	56.7	69.8	6.1	5.3	7	10.6	15	23.5	26.5	30.9	43.5	50.4
70	SBUX	STARBUCKS CORP.	0.95	18.3	10.5	12	16.6	23.3	31	41.3	42.1	64	61.8	9.9	3.5	4.1	10.6	15.4	21.5	26.3	34	39.3	50.8
71	SRCL	STERICYCLE INC.	0.9	62.6	66.1	58.3	82.2	95.7	96	121.6	134.1	151.6	128.9	36.5	46.4	44.4	50.6	73.1	75.8	93.2	108.6	110.6	71.5
72	SYK	STRYKER CORP.	0.9	76.9	74.9	52.7	59.7	65.2	57.2	75.6	98.2	105.3	123.6	54.9	35.4	30.8	42.7	43.7	49.4	55.2	74	89.8	86.7
73	SYY	SYSCO CORP.	0.75	36.7	35	29.5	32	32.8	32.4	43.4	41.2	42	57.1	29.9	20.7	19.4	27	25.1	27	30.5	34.1	35.4	38.8
74	TGT	TARGET CORP.	0.8	70.8	59.6	51.8	60.7	61	65.8	73.5	76.6	85.8	84.1	48.8	25.6	25	48.2	45.3	47.3	58	54.7	68.1	65.5
75	TJX	TJX COMPANIES	0.85	16.2	18.8	20.3	24.3	32.8	46.7	64.1	69.8	76.9	83.6	12.9	8.9	9.6	17.9	21.3	31.7	42.4	51.9	63.5	65.6
76	UNH	UNITEDHEALTH GRP.	0.85	59.5	57.9	33.3	38.1	53.5	60.8	75.9	104	126.2	164	45.8	14.5	16.2	27.1	36.4	49.8	51.4	69.6	95	107.5
77	VAR	VARIAN MEDICAL	0.95	53.2	65.8	47.8	71	72.2	72.6	80.7	89.9	96.7	106.7	37.3	33.1	27.1	35.5	48.7	52.9	63.1	76.7	71.1	73.2
78	VZ	VERIZON	0.75	46.2	44.3	34.8	36	40.3	48.8	54.3	53.7	50.9	56.9	35.6	23.1	26.1	26	32.3	36.8	41.5	45.1	38.1	43.8
79	WBA	WALGREENS BOOTS	0.9	49.1	39	40.7	40.2	47.1	37.8	60.9	78	97.3	102.8	35.8	21.3	21.4	26.3	30.3	28.5	37.1	55.3	73	71.5
80	WMT	WAL-MART STORES	0.65	51.4	63.8	57.5	56.3	60	77.6	81.4	88.1	91	75.2	42.1	43.1	46.3	47.8	48.3	57.2	67.7	72.3	56.3	60.2
81	WM	WASTE MANAGEMENT	0.75	41.2	39.3	34.2	37.3	39.7	36.3	46.4	51.9	55.9	71.8	32.4	24.5	22.1	31.1	27.8	30.8	33.7	40.3	45.9	50.4
82	WAT	WATERS CORP.	0.95	81.5	81.8	63.1	81	100	94.5	108.9	117.7	137.4	162.5	48.6	32.2	30	56	70.9	73	85	93.6	111.8	112
83	WFM	WHOLE FOODS MKT.	0.9	26.8	21.2	17.2	25.9	37.2	50.9	65.6	57.8	57.6	35.6	18	3.5	4.5	13.4	23.9	34.7	40.7	36.1	28.7	27.7
84	GWW	GRAINGER (W.W.)	0.9	98.6	94	102.5	139.1	193.2	221.8	276.4	269.7	257	240.7	68.8	58.9	59.9	96.1	124.3	172.5	201.5	223.9	189.6	176.9

Southern California Edison Company
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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
MMM	5.6	4.4	3.9	4.0	3.8	3.7	4.5	6.2	7.6	8.7
High	97.00	84.80	84.30	91.50	98.20	95.50	140.40	168.20	170.50	182.30
Low	72.9	50	40.9	68	68.6	82	94	123.6	134	134.6
Avg	85.0	67.4	62.6	79.8	83.4	88.8	117.2	145.9	152.3	158.5
bvEquity	15.06	15.40	16.10	19.98	22.10	23.89	25.99	23.52	19.93	18.24
APH	6.4	4.7	3.8	3.9	3.7	3.9	4.7	5.3	5.4	5.1
High	23.60	26.10	23.60	27.00	29.60	32.60	44.70	55.70	60.50	69.20
Low	15.3	9.2	10.8	18.9	19.5	22.5	32.9	42.1	47.4	44.5
Avg	19.5	17.7	17.2	23.0	24.6	27.6	38.8	48.9	54.0	56.9
bvEquity	3.05	3.74	4.49	5.83	6.64	7.13	8.32	9.21	9.95	11.22
AAPL	10.0	6.9	5.4	6.2	5.5	5.3	3.6	4.9	5.6	4.6
High	29.00	28.60	30.60	46.70	61.00	100.70	82.20	119.80	134.50	118.70
Low	11.7	11.3	11.2	27.2	44.4	58.4	55	70.5	92	89.5
Avg	20.4	20.0	20.9	37.0	52.7	79.6	68.6	95.2	113.3	104.1
bvEquity	2.03	2.88	3.90	5.94	9.62	14.88	18.81	19.33	20.21	22.71
T	1.5	1.8	1.5	1.5	1.6	2.0	2.1	2.0	1.8	1.9
High	43.00	41.90	29.50	29.60	31.90	38.60	39.00	37.50	36.40	43.90
Low	32.7	20.9	21.4	23.8	27.2	29	32.8	31.7	31	33.4
Avg	37.9	31.4	25.5	26.7	29.6	33.8	35.9	34.6	33.7	38.7
bvEquity	24.43	17.72	16.85	18.14	18.40	17.23	17.06	17.13	18.36	20.01
ADP	4.7	3.9	3.7	3.4	4.3	4.5	5.6	5.9	6.4	9.0
High	51.50	46.00	44.50	47.20	55.10	60.00	83.80	86.50	90.70	103.90
Low	43.9	30.8	32	26.5	44.7	50.9	57.8	70.5	64.3	76.6
Avg	47.7	38.4	38.3	36.9	49.9	55.5	70.8	78.5	77.5	90.3
bvEquity	10.16	9.79	10.29	10.88	11.70	12.44	12.73	13.36	12.10	10.07
BLL	4.0	3.3	3.1	3.4	4.3	5.4	5.9	7.4	8.3	5.1
High	14.00	14.00	13.10	17.40	20.30	22.70	26.00	35.20	38.60	41.10
Low	10.9	6.8	9.1	11.7	14.8	17.8	20.8	23.9	29	31.2
Avg	12.5	10.4	11.1	14.6	17.6	20.3	23.4	29.6	33.8	36.2
bvEquity	3.08	3.11	3.55	4.31	4.11	3.76	3.97	4.00	4.09	7.11
BAX	5.2	5.7	4.8	4.4	4.8	4.9	4.9	4.7	3.4	2.7
High	61.10	71.50	61.00	61.90	62.50	68.90	74.60	77.30	74.00	50.20
Low	46.1	47.4	45.5	40.3	47.6	49	62.8	66.3	32.2	34.1
Avg	53.6	59.5	53.3	51.1	55.1	59.0	68.7	71.8	53.1	42.2
bvEquity	10.28	10.51	11.04	11.64	11.44	12.14	14.14	15.28	15.56	15.76
BDX	4.6	4.0	3.3	3.4	3.5	3.5	4.0	4.7	4.7	4.5
High	85.90	93.20	80.00	85.50	89.80	80.60	110.90	142.60	157.50	181.80
Low	69.3	58.1	60.4	66.5	69.6	71.6	78.7	105.2	128.9	129.5
Avg	77.6	75.7	70.2	76.0	79.7	76.1	94.8	123.9	143.2	155.7
bvEquity	16.76	19.10	21.00	22.67	23.07	21.74	23.50	26.16	30.16	34.90
BFB	5.3	4.4	3.6	4.5	5.0	7.1	8.0	9.2	11.6	12.7
High	21.30	21.00	18.50	24.30	27.30	35.50	38.40	49.00	55.50	51.70
Low	16.8	13.5	11.7	16.3	20.7	25.7	30.5	36.7	43.4	43.8
Avg	19.1	17.3	15.1	20.3	24.0	30.6	34.5	42.9	49.5	47.8
bvEquity	3.61	3.92	4.17	4.52	4.80	4.33	4.29	4.66	4.26	3.76

Southern California Edison Company
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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CPB	9.8	9.6	10.6	14.6	10.6	10.9	12.3	9.5	10.2	12.6
High	42.70	40.80	35.80	37.60	35.70	37.20	48.80	46.70	55.10	67.90
Low	34.2	27.3	24.6	32.2	29.7	31.2	34.8	39.6	42.9	50.5
Avg	38.5	34.1	30.2	34.9	32.7	34.2	41.8	43.2	49.0	59.2
bvEquity	3.91	3.56	2.86	2.39	3.08	3.14	3.39	4.53	4.81	4.70
CAH	3.2	2.2	1.4	1.8	2.7	2.3	3.0	4.0	4.4	3.9
High	76.10	62.30	39.90	39.30	47.10	44.50	67.80	83.40	91.90	90.00
Low	56.4	27.8	24.9	29.7	37.5	36.9	41.1	63.1	74.8	62.7
Avg	66.3	45.1	32.4	34.5	42.3	40.7	54.5	73.3	83.4	76.4
bvEquity	20.49	20.87	22.97	19.52	15.73	17.43	17.88	18.29	19.04	19.74
CERN	4.3	3.0	3.4	4.0	4.8	4.9	5.7	5.8	6.0	4.9
High	16.50	15.00	21.50	24.40	37.20	44.20	59.40	66.40	75.70	67.50
Low	11	7.6	8.3	18	23	29.7	39.4	48.4	55.8	47
Avg	13.8	11.3	14.9	21.2	30.1	37.0	49.4	57.4	65.8	57.3
bvEquity	3.23	3.79	4.42	5.26	6.27	7.52	8.72	9.82	10.90	11.65
CHRW	8.7	8.2	7.6	9.6	10.1	7.5	7.8	9.5	9.0	8.2
High	58.20	67.40	61.70	81.00	82.60	71.80	67.90	77.50	76.20	77.90
Low	42.1	36.5	37.4	51.2	62.3	50.8	53.7	50.2	59.7	60.3
Avg	50.2	52.0	49.6	66.1	72.5	61.3	60.8	63.9	68.0	69.1
bvEquity	5.79	6.31	6.49	6.86	7.15	8.19	7.83	6.75	7.59	8.46
CHD	3.4	3.2	2.6	2.7	2.9	3.5	3.8	4.4	5.4	5.9
High	14.30	16.40	15.60	17.80	23.20	29.60	33.50	40.50	45.40	53.70
Low	10.6	11.9	11.4	14.8	16.9	22.1	26.9	30.5	38.7	38.4
Avg	12.5	14.2	13.5	16.3	20.1	25.9	30.2	35.5	42.1	46.1
bvEquity	3.69	4.42	5.22	6.13	6.87	7.30	7.86	8.08	7.83	7.79
CI	3.2	2.2	1.5	1.5	1.6	1.4	2.0	2.3	3.1	2.6
High	57.60	57.00	38.10	39.30	52.90	54.50	88.60	105.70	170.70	149.00
Low	42.3	8	12.7	29.1	36.8	39	53.9	73.5	100.7	115
Avg	50.0	32.5	25.4	34.2	44.9	46.8	71.3	89.6	135.7	132.0
bvEquity	15.81	15.11	16.52	22.16	27.67	32.56	36.07	39.33	43.87	50.16
CTAS	2.8	1.9	1.6	1.6	1.9	2.4	2.9	3.7	4.7	5.8
High	42.90	33.90	30.80	29.70	35.30	45.60	59.70	80.40	94.30	122.20
Low	31.1	19.5	18.1	23.1	26.4	35.2	41.2	55.3	75.9	80
Avg	37.0	26.7	24.5	26.4	30.9	40.4	50.5	67.9	85.1	101.1
bvEquity	13.23	14.17	15.08	16.04	16.66	16.83	17.46	18.37	18.02	17.49
KO	6.6	5.8	4.9	4.7	4.8	5.2	5.4	5.7	6.3	7.7
High	32.20	32.80	29.70	32.90	35.90	40.70	43.40	45.00	43.90	47.10
Low	22.8	20.1	18.7	24.7	30.6	33.3	36.5	36.9	36.6	39.9
Avg	27.5	26.5	24.2	28.8	33.3	37.0	40.0	41.0	40.3	43.5
bvEquity	4.17	4.56	4.91	6.07	6.88	7.17	7.44	7.24	6.43	5.65
CMCSA	2.1	1.3	1.0	1.2	1.4	1.7	2.3	2.7	2.7	2.8
High	15.10	11.40	9.00	11.20	13.60	19.10	26.00	29.70	32.50	35.70
Low	8.7	6.3	5.6	7.6	9.6	12.1	18.6	23.9	25	26.2
Avg	11.9	8.9	7.3	9.4	11.6	15.6	22.3	26.8	28.8	31.0
bvEquity	5.59	6.94	7.28	7.76	8.37	9.06	9.57	10.09	10.56	11.03

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
CAG	2.7	1.9	1.7	2.2	2.2	2.4	2.9	2.6	3.4	4.3
High	27.70	24.90	23.70	26.30	26.70	31.10	37.30	37.50	45.50	48.90
Low	22.8	13.5	14	21	22.2	23.6	29.8	28.1	33.4	33.6
Avg	25.3	19.2	18.9	23.7	24.5	27.4	33.6	32.8	39.5	41.3
bvEquity	9.23	10.19	10.86	10.91	11.29	11.17	11.72	12.51	11.52	9.53
STZ	1.8	1.6	1.4	1.6	1.5	1.9	2.5	3.1	3.9	4.4
High	29.20	23.80	17.60	22.50	23.20	37.00	71.60	100.80	144.90	173.50
Low	18.8	10.7	10.7	14.6	16.4	18.5	28.4	68.5	96.5	130.2
Avg	24.0	17.3	14.2	18.6	19.8	27.8	50.0	84.7	120.7	151.9
bvEquity	13.67	10.76	10.15	11.87	12.96	14.42	20.21	27.14	30.91	34.15
COST	3.1	2.9	2.2	2.6	3.0	3.3	4.2	4.8	5.5	5.9
High	72.70	75.20	61.30	73.20	88.70	106.00	126.10	146.80	169.70	169.60
Low	51.5	43.9	38.2	53.4	69.5	78.8	98.9	109.5	117	138.6
Avg	62.1	59.6	49.8	63.3	79.1	92.4	112.5	128.2	143.4	154.1
bvEquity	19.76	20.49	22.12	23.98	26.31	28.12	26.70	26.46	26.18	25.93
BCR	4.9	4.5	3.7	4.1	4.8	4.3	4.7	5.9	8.3	9.6
High	95.30	101.60	88.40	95.70	113.80	108.30	141.00	174.50	202.50	239.40
Low	76.6	70	68.9	75.2	80.8	84.4	97.1	125	163.1	172.2
Avg	86.0	85.8	78.7	85.5	97.3	96.4	119.1	149.8	182.8	205.8
bvEquity	17.45	19.17	21.38	21.04	20.14	22.33	25.27	25.54	21.93	21.37
DE	4.2	3.9	3.0	5.1	5.0	4.6	3.9	3.2	3.6	4.2
High	93.70	94.90	56.90	84.90	99.80	89.70	95.60	94.90	98.20	104.80
Low	45.1	28.5	24.5	48.3	59.9	69.5	79.5	78.9	71.9	70.2
Avg	69.4	61.7	40.7	66.6	79.9	79.6	87.6	86.9	85.1	87.5
bvEquity	16.38	15.88	13.43	13.15	15.83	17.20	22.55	26.85	23.76	21.00
XRAY	4.2	3.4	2.5	2.6	2.6	2.7	2.7	2.9	3.4	2.3
High	47.80	47.10	36.80	38.20	40.40	41.40	51.00	56.30	63.40	65.80
Low	29.4	22.8	21.8	27.8	28.3	34.8	39.4	43	49.4	53.4
Avg	38.6	35.0	29.3	33.0	34.4	38.1	45.2	49.7	56.4	59.6
bvEquity	9.22	10.37	11.57	12.72	13.01	14.28	16.67	17.15	16.59	26.00
EW	3.5	3.6	3.9	5.9	6.6	7.2	5.7	5.7	6.6	8.1
High	13.20	16.70	22.10	42.70	45.90	55.40	47.50	67.10	83.40	121.80
Low	11.4	10.4	13.2	21.2	30.8	33.9	30.3	31.5	61.4	72.2
Avg	12.3	13.6	17.7	32.0	38.4	44.7	38.9	49.3	72.4	97.0
bvEquity	3.47	3.81	4.52	5.40	5.78	6.17	6.80	8.65	10.89	12.00
LLY	5.1	4.8	4.8	3.7	3.4	3.8	3.7	4.2	6.0	5.8
High	61.00	57.50	40.80	38.10	41.90	54.00	58.40	75.10	92.90	85.40
Low	49.1	28.6	27.2	32	33.5	38.3	47.5	50.5	68.3	64.2
Avg	55.1	43.1	34.0	35.1	37.7	46.2	53.0	62.8	80.6	74.8
bvEquity	10.88	8.99	7.11	9.53	11.23	12.31	14.36	14.83	13.52	12.95
EFX	4.7	2.8	2.2	2.4	2.4	3.0	3.5	3.9	5.1	5.5
High	46.30	39.90	31.60	36.60	39.90	55.50	69.60	82.60	114.50	137.00
Low	35.2	19.4	19.6	27.6	28.6	37.9	52.8	64.8	79.6	91.7
Avg	40.8	29.7	25.6	32.1	34.3	46.7	61.2	73.7	97.1	114.4
bvEquity	8.76	10.59	11.60	13.37	14.17	15.34	17.73	18.94	19.09	20.84
EXPD	8.6	6.1	4.5	5.8	5.4	4.2	4.1	4.3	4.9	5.0

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
High	54.50	49.90	38.10	57.20	56.20	47.50	46.90	47.20	51.80	56.40
Low	38.3	24	23.9	32.4	38.3	34.2	34.8	38.1	42.2	40.4
Avg	46.4	37.0	31.0	44.8	47.3	40.9	40.9	42.7	47.0	48.4
bvEquity	5.39	6.11	6.89	7.77	8.83	9.64	10.06	10.02	9.52	9.78
ESRX	15.5	17.9	7.7	7.0	8.0	3.3	2.2	2.7	3.1	2.9
High	37.20	39.60	44.90	55.70	60.90	66.10	70.80	86.30	94.60	87.90
Low	16.2	24.2	21.4	37.8	34.5	45.7	53.1	64.6	68.1	64.5
Avg	26.7	31.9	33.2	46.8	47.7	55.9	62.0	75.5	81.4	76.2
bvEquity	1.73	1.78	4.32	6.65	5.97	16.84	28.41	27.93	26.65	26.24
XOM	3.9	3.4	3.1	2.5	2.5	2.5	2.4	2.3	1.9	2.1
High	95.30	96.10	82.70	73.70	88.20	93.70	101.70	104.80	93.40	95.60
Low	69	56.5	61.9	55.9	67	77.1	84.8	86.2	66.6	71.6
Avg	82.2	76.3	72.3	64.8	77.6	85.4	93.3	95.5	80.0	83.6
bvEquity	21.25	22.66	23.05	26.44	31.05	34.73	38.49	40.83	41.31	40.72
FISV	3.6	2.7	2.2	2.5	2.5	2.8	3.7	4.6	6.5	8.4
High	29.90	28.40	25.50	30.30	32.70	40.60	59.30	73.30	97.80	111.50
Low	22.1	13.9	14.7	22.4	24.4	28.8	39.5	53.7	69.1	85.6
Avg	26.0	21.2	20.1	26.4	28.6	34.7	49.4	63.5	83.5	98.6
bvEquity	7.28	7.90	9.10	10.44	11.37	12.28	13.39	13.84	12.76	11.80
FLIR	6.7	6.6	3.8	3.3	3.0	2.1	2.5	2.9	2.5	2.6
High	36.40	45.50	33.30	33.30	37.30	27.10	33.80	37.40	34.50	37.20
Low	14.8	23.7	18.8	24	21.9	18	22.9	28.3	25.1	26.5
Avg	25.6	34.6	26.1	28.7	29.6	22.6	28.4	32.9	29.8	31.9
bvEquity	3.80	5.25	6.91	8.72	9.88	10.58	11.22	11.50	11.77	12.16
FL	1.2	0.8	0.8	1.2	1.6	2.1	2.2	2.7	3.5	3.3
High	24.80	18.20	13.00	20.00	25.50	37.70	41.60	59.20	77.30	79.40
Low	11.8	3.7	7.1	11.1	16.7	23.5	31.1	36.7	51.1	50.9
Avg	18.3	11.0	10.1	15.6	21.1	30.6	36.4	48.0	64.2	65.2
bvEquity	14.78	13.62	12.43	12.77	13.51	14.88	16.49	17.51	18.26	19.63
GD	3.1	2.6	1.8	2.0	1.8	2.0	2.2	3.1	4.1	4.3
High	94.60	95.10	70.80	79.00	78.30	74.50	95.80	146.10	153.80	180.10
Low	70.6	47.8	35.3	55.5	53.9	61.1	64.5	93.9	130.9	121.6
Avg	82.6	71.5	53.1	67.3	66.1	67.8	80.2	120.0	142.4	150.9
bvEquity	26.68	27.57	29.11	34.00	36.46	34.66	36.62	38.35	35.09	35.40
GIS	3.6	3.6	3.5	4.5	4.2	4.0	4.6	4.9	5.6	7.6
High	30.80	36.00	36.00	39.00	40.80	41.90	53.10	55.60	59.90	72.90
Low	27.1	25.5	23.2	33.1	34.5	36.8	40.4	46.7	47.4	53.5
Avg	29.0	30.8	29.6	36.1	37.7	39.4	46.8	51.2	53.7	63.2
bvEquity	7.97	8.52	8.55	8.06	9.05	9.89	10.16	10.54	9.51	8.31
GPC	3.1	2.5	2.1	2.6	3.0	3.3	3.6	4.3	4.4	4.3
High	51.70	46.30	39.80	51.60	62.20	66.90	85.40	109.00	108.10	106.00
Low	46	29.9	24.9	36.9	46.1	55.6	64.4	76.5	78.8	76.5
Avg	48.9	38.1	32.4	44.3	54.2	61.3	74.9	92.8	93.5	91.3
bvEquity	15.66	15.47	15.54	17.11	17.80	18.66	20.64	21.74	21.30	21.25

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
HAS	3.1	3.2	2.5	3.4	3.5	3.2	3.7	4.3	5.4	5.4
High	33.50	41.70	32.60	50.20	48.40	40.00	55.20	59.40	84.40	88.50
Low	25.3	21.6	21.1	30.2	31.4	31.7	35	47.5	51.4	65.5
Avg	29.4	31.7	26.9	40.2	39.9	35.9	45.1	53.5	67.9	77.0
bvEquity	9.56	9.77	10.81	11.70	11.39	11.36	12.27	12.31	12.55	14.15
HSIC	3.0	2.3	2.0	2.3	2.5	2.6	3.2	3.8	4.2	4.6
High	63.40	63.60	56.90	62.60	75.00	82.90	116.10	139.10	161.60	183.00
Low	45.8	32.1	33.6	51	58.5	64.7	81.6	109.3	126.2	142.6
Avg	54.6	47.9	45.3	56.8	66.8	73.8	98.9	124.2	143.9	162.8
bvEquity	18.25	20.75	22.74	25.04	26.64	28.40	31.14	33.01	34.25	35.09
HSY	17.0	19.1	15.9	12.3	14.0	16.0	14.7	14.3	17.3	24.1
High	56.80	44.30	42.30	52.10	62.30	74.70	101.40	108.70	111.40	117.80
Low	38.2	32.1	30.3	35.8	46.2	59.3	72.5	87.9	82.4	82.4
Avg	47.5	38.2	36.3	44.0	54.3	67.0	87.0	98.3	96.9	100.1
bvEquity	2.79	2.01	2.28	3.57	3.87	4.20	5.90	6.88	5.60	4.15
HD	2.9	2.3	2.1	2.8	3.0	4.6	6.9	11.1	18.7	28.8
High	42.00	31.10	29.40	37.00	42.50	65.90	82.50	106.00	135.50	139.00
Low	25.6	17	17.5	26.6	28.1	41.9	62.4	74	92.2	109.6
Avg	33.8	24.1	23.5	31.8	35.3	53.9	72.5	90.0	113.9	124.3
bvEquity	11.60	10.48	10.95	11.53	11.64	11.81	10.53	8.10	6.09	4.32
HRL	2.7	2.3	2.3	2.7	2.9	2.8	3.3	3.7	4.5	4.9
High	10.50	10.70	10.10	13.10	15.30	15.80	23.10	27.70	40.40	45.70
Low	7.5	6.2	7.3	9.4	12.3	13.6	15.7	21.4	25.1	33.2
Avg	9.0	8.5	8.7	11.3	13.8	14.7	19.4	24.6	32.8	39.5
bvEquity	3.38	3.60	3.85	4.25	4.78	5.21	5.83	6.57	7.21	8.00
HUM	3.2	2.2	1.1	1.4	1.6	1.5	1.5	1.9	2.7	2.6
High	81.50	88.10	46.20	61.30	90.90	96.50	105.80	151.50	219.80	217.80
Low	51	22.3	18.6	43.1	54.6	59.9	65.9	91	137.5	150
Avg	66.3	55.2	32.4	52.2	72.8	78.2	85.9	121.3	178.7	183.9
bvEquity	21.01	25.05	30.17	37.51	45.12	52.52	58.18	62.48	67.12	70.66
IBM	5.3	6.5	7.8	7.3	9.4	11.4	10.1	10.4	11.5	8.4
High	121.50	130.90	132.90	147.50	194.90	211.80	215.90	199.20	176.30	170.00
Low	88.8	69.5	81.8	116	146.6	177.3	172.6	150.5	131.6	116.9
Avg	105.2	100.2	107.4	131.8	170.8	194.6	194.3	174.9	154.0	143.5
bvEquity	19.74	15.31	13.75	18.15	18.14	17.14	19.25	16.80	13.38	17.03
IFF	5.7	4.9	4.0	4.3	4.5	4.1	4.7	5.1	5.7	6.0
High	54.80	48.00	42.60	56.10	66.30	67.80	90.30	105.80	123.10	143.60
Low	45.7	24.7	25	39.3	51.2	52.1	67.5	82.9	97.6	97.2
Avg	50.3	36.4	33.8	47.7	58.8	60.0	78.9	94.4	110.4	120.4
bvEquity	8.87	7.46	8.50	11.08	13.05	14.48	16.64	18.39	19.34	20.20
SJM	1.7	1.3	1.1	1.3	1.5	1.7	2.1	1.8	1.9	2.3
High	64.30	56.70	62.70	66.30	80.30	89.40	114.70	107.70	125.30	157.30
Low	46.6	37.2	34.1	53.3	61.2	70.5	86.5	87.1	97.3	117.4
Avg	55.5	47.0	48.4	59.8	70.8	80.0	100.6	97.4	111.3	137.4
bvEquity	32.29	37.33	43.21	45.53	46.59	47.59	48.91	54.37	59.77	60.33

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
JNJ	4.5	4.1	3.3	3.2	3.0	3.0	3.4	3.8	3.7	4.3
High	68.80	72.80	65.40	66.20	68.10	72.70	96.00	109.50	106.50	126.10
Low	59.7	52.1	46.3	56.9	57.5	61.7	70.3	86.1	81.8	94.3
Avg	64.3	62.5	55.9	61.6	62.8	67.2	83.2	97.8	94.2	110.2
bvEquity	14.42	15.30	16.86	19.52	20.81	22.14	24.79	25.66	25.45	25.93
K	9.0	9.6	9.2	8.7	9.8	8.9	7.5	7.1	9.7	13.5
High	56.90	58.50	54.10	56.00	57.70	57.20	68.00	69.50	73.70	87.20
Low	48.7	40.3	35.6	47.3	48.1	46.3	56	55.7	61.1	68.7
Avg	52.8	49.4	44.9	51.7	52.9	51.8	62.0	62.6	67.4	78.0
bvEquity	5.84	5.14	4.88	5.93	5.42	5.82	8.24	8.80	6.96	5.76
KR	3.8	3.5	3.0	2.7	3.0	3.2	3.7	4.6	5.6	5.0
High	16.00	15.50	13.50	12.10	12.90	13.60	21.90	32.50	42.80	42.40
Low	11.5	11.1	9.7	9.5	10.5	10.5	12.6	17.6	27.3	28.7
Avg	13.8	13.3	11.6	10.8	11.7	12.1	17.3	25.1	35.1	35.6
bvEquity	3.60	3.85	3.88	4.02	3.91	3.82	4.70	5.43	6.31	7.15
LH	4.6	4.3	3.6	3.6	3.5	3.2	3.3	3.2	2.9	2.3
High	82.30	80.80	76.70	89.50	100.90	95.30	108.00	109.80	131.20	141.30
Low	65.1	52.9	53.3	69.5	74.6	81.6	85.8	87.3	105.8	97.8
Avg	73.7	66.9	65.0	79.5	87.8	88.5	96.9	98.6	118.5	119.6
bvEquity	15.86	15.57	17.86	22.39	25.13	27.33	29.07	31.21	41.08	51.21
MAT	3.8	2.7	2.4	3.2	3.4	3.9	4.5	4.2	3.1	4.0
High	29.70	22.00	21.00	26.70	29.40	38.00	48.50	47.70	31.20	34.80
Low	18.8	10.9	10.4	19.1	22.7	27.7	35.5	28.7	19.4	23.8
Avg	24.3	16.5	15.7	22.9	26.1	32.9	42.0	38.2	25.3	29.3
bvEquity	6.36	6.15	6.45	7.26	7.64	8.36	9.27	9.15	8.24	7.39
MKC	4.7	4.2	3.6	3.9	4.1	4.7	4.9	4.8	5.8	7.1
High	39.70	42.10	36.80	47.80	51.30	66.40	75.30	77.10	87.50	107.80
Low	33.9	28.2	28.1	35.4	43.4	49.9	60.8	62.8	70.7	78.4
Avg	36.8	35.2	32.5	41.6	47.4	58.2	68.1	70.0	79.1	93.1
bvEquity	7.83	8.30	9.12	10.56	11.58	12.49	13.83	14.48	13.62	13.05
MDT	5.2	3.9	2.8	2.7	2.3	2.3	2.6	2.3	1.8	2.1
High	58.00	57.00	44.90	46.70	43.30	44.80	58.80	75.70	79.50	89.30
Low	44.9	28.3	24.1	30.8	30.2	35.7	41.2	53.3	55.5	71
Avg	51.5	42.7	34.5	38.8	36.8	40.3	50.0	64.5	67.5	80.2
bvEquity	9.93	10.84	12.38	14.13	15.71	17.44	18.92	28.45	37.33	37.76
MRK	6.3	4.9	2.1	2.0	1.9	2.4	2.6	3.3	3.3	3.7
High	61.60	61.20	38.40	41.60	37.90	48.00	50.40	62.20	63.60	65.50
Low	42.3	22.8	20	30.7	29.5	36.9	40.8	49.3	45.7	48
Avg	52.0	42.0	29.2	36.2	33.7	42.5	45.6	55.8	54.7	56.8
bvEquity	8.24	8.64	13.95	18.32	17.79	17.73	17.26	17.07	16.60	15.32
TAP	1.3	1.3	1.2	1.1	1.1	1.0	1.1	1.5	2.0	2.2
High	57.70	59.50	51.30	51.10	50.40	46.30	56.50	77.90	95.70	112.20
Low	37.6	35	30.8	38.4	38	38	41.3	50.9	63.9	80.8
Avg	47.7	47.3	41.1	44.8	44.2	42.2	48.9	64.4	79.8	96.5
bvEquity	36.20	36.05	35.29	39.90	41.27	41.47	43.61	42.90	39.46	44.53

Southern California Edison Company
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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
MON	6.4	6.8	4.5	3.6	3.4	3.8	4.6	5.8	6.6	7.8
High	116.30	145.80	93.40	87.10	78.70	94.80	116.80	128.80	126.00	114.30
Low	49.1	63.5	66.6	44.6	58.9	69.7	94	104.1	81.2	83.7
Avg	82.7	104.7	80.0	65.9	68.8	82.3	105.4	116.5	103.6	99.0
bvEquity	12.88	15.42	17.77	18.53	20.09	21.85	22.94	20.05	15.65	12.65
NKE	4.4	3.8	3.1	4.0	4.1	4.6	5.5	6.8	8.3	7.8
High	17.00	17.70	16.70	23.10	24.60	28.70	40.10	49.90	68.20	65.40
Low	11.9	10.7	9.6	15.2	17.4	21.3	25.7	34.9	45.3	49
Avg	14.5	14.2	13.2	19.2	21.0	25.0	32.9	42.4	56.8	57.2
bvEquity	3.26	3.74	4.23	4.76	5.11	5.43	5.96	6.23	6.82	7.35
NOC	1.5	1.3	1.2	1.4	1.4	1.6	2.0	3.1	5.0	7.1
High	85.20	83.40	57.30	69.80	72.50	71.30	116.20	153.20	194.00	253.80
Low	66.2	34	33.8	53.5	49.2	56.6	64.2	109.2	141.6	175
Avg	75.7	58.7	45.6	61.7	60.9	64.0	90.2	131.2	167.8	214.4
bvEquity	50.19	44.40	38.90	43.97	43.65	40.42	44.56	42.74	33.47	30.25
PDCO	3.8	3.0	2.1	2.3	2.5	2.5	2.9	3.0	3.3	3.1
High	40.10	37.80	28.30	32.80	36.90	36.40	44.40	49.50	53.10	50.40
Low	28.3	15.8	16.1	24.1	26.2	29	34.3	37	42.6	36.5
Avg	34.2	26.8	22.2	28.5	31.6	32.7	39.4	43.3	47.9	43.5
bvEquity	9.05	8.97	10.70	12.29	12.68	12.84	13.69	14.41	14.61	13.95
PAYX	8.8	7.2	7.6	7.6	7.4	7.5	8.3	9.0	9.8	10.5
High	47.10	37.50	32.90	32.80	33.90	34.70	45.90	48.20	54.80	62.20
Low	36	23.2	20.3	24.7	25.1	29.1	31.5	39.8	41.6	45.8
Avg	41.6	30.4	26.6	28.8	29.5	31.9	38.7	44.0	48.2	54.0
bvEquity	4.73	4.22	3.52	3.80	4.01	4.28	4.64	4.88	4.92	5.12
PEP	7.0	7.0	5.7	5.1	4.8	4.9	5.1	6.5	9.0	12.7
High	79.00	79.80	64.50	68.10	71.90	73.70	87.10	100.70	103.40	110.90
Low	61.9	49.7	43.8	58.8	58.5	62.2	68.6	77	76.5	93.2
Avg	70.5	64.8	54.2	63.5	65.2	68.0	77.9	88.9	90.0	102.1
bvEquity	10.04	9.24	9.45	12.34	13.45	13.88	15.13	13.77	9.99	8.05
PRGO	3.5	3.9	3.0	4.8	5.9	5.8	5.7	3.3	2.6	2.0
High	36.90	43.10	40.90	68.40	104.70	120.80	157.50	171.60	215.70	152.40
Low	16.1	27.7	18.5	37.5	62.3	90.2	98.8	125.4	140.4	79.7
Avg	26.5	35.4	29.7	53.0	83.5	105.5	128.2	148.5	178.1	116.1
bvEquity	7.49	9.05	10.01	10.93	14.18	18.16	22.33	44.90	68.93	57.22
PFE	2.5	2.1	1.6	1.6	1.8	2.1	2.5	2.6	3.0	3.2
High	27.70	24.20	19.00	20.40	21.90	26.10	32.50	33.10	36.50	37.40
Low	22.2	14.3	11.6	14	16.6	20.8	25.3	27.5	28.5	28.3
Avg	25.0	19.3	15.3	17.2	19.3	23.5	28.9	30.3	32.5	32.9
bvEquity	9.79	9.06	9.84	11.05	10.90	11.00	11.54	11.63	10.91	10.15
PG	3.4	3.0	2.5	2.5	2.8	2.8	3.2	3.4	3.3	3.7
High	75.20	73.80	63.50	65.40	67.70	71.00	85.80	93.90	91.80	90.30
Low	60.4	54.9	43.9	39.4	57.6	59.1	68.4	75.3	65	74.5
Avg	67.8	64.4	53.7	52.4	62.7	65.1	77.1	84.6	78.4	82.4
bvEquity	20.10	21.67	21.82	21.19	22.67	23.51	23.76	25.02	24.12	22.09

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
QCOM	4.7	4.2	3.5	3.3	3.6	3.4	3.2	3.3	2.7	2.7
High	47.70	56.90	48.70	50.30	59.80	68.90	74.30	82.00	75.30	71.60
Low	35.2	28.2	32.6	31.6	46	53.1	59	67.7	45.9	42.2
Avg	41.5	42.6	40.7	41.0	52.9	61.0	66.7	74.9	60.6	56.9
bvEquity	8.87	10.23	11.51	12.56	14.50	17.86	20.54	22.45	22.05	21.08
DGX	3.3	2.7	2.6	2.2	2.3	2.4	2.2	2.1	2.4	2.3
High	58.60	59.90	62.80	61.70	61.20	64.90	64.10	68.50	89.00	93.60
Low	48	38.7	42.4	40.8	45.1	53.3	52.5	50.5	60.1	59.7
Avg	53.3	49.3	52.6	51.3	53.2	59.1	58.3	59.5	74.6	76.7
bvEquity	16.35	18.03	20.61	22.94	23.52	24.88	26.86	28.65	31.32	33.27
RTN	2.2	2.1	1.8	1.9	1.8	2.2	2.4	3.0	3.5	3.9
High	65.90	67.50	53.80	60.10	53.10	59.30	91.40	111.50	130.00	152.60
Low	51	41.8	33.2	42.7	38.3	47.5	52.2	87.6	95.3	115.7
Avg	58.5	54.7	43.5	51.4	45.7	53.4	71.8	99.6	112.7	134.2
bvEquity	27.17	26.07	24.18	26.41	25.65	24.30	29.78	33.05	32.44	34.11
RSG	4.3	2.1	1.1	1.4	1.4	1.3	1.5	1.7	1.9	2.2
High	35.00	36.50	29.80	32.90	33.10	31.30	35.60	41.10	45.30	58.00
Low	26.2	18.3	15	25.2	24.7	25.2	29.3	31.4	38.9	41.8
Avg	30.6	27.4	22.4	29.1	28.9	28.3	32.5	36.3	42.1	49.9
bvEquity	7.16	13.14	19.56	20.17	20.62	21.06	21.64	21.96	22.24	22.58
RMD	4.3	3.1	2.9	3.8	3.0	3.0	4.4	4.1	5.2	5.2
High	28.10	26.20	26.70	35.90	35.40	42.90	57.30	57.60	75.30	70.90
Low	19.2	14.5	15.7	25	23.4	24.4	42	41.5	49	50.8
Avg	23.7	20.4	21.2	30.5	29.4	33.7	49.7	49.6	62.2	60.9
bvEquity	5.44	6.56	7.27	7.96	9.96	11.37	11.33	11.94	11.92	11.68
ROST	4.3	4.2	4.5	5.3	6.5	8.0	7.7	7.8	8.6	9.1
High	8.80	10.40	12.60	16.60	24.60	35.40	41.00	48.10	56.70	69.80
Low	6.1	5.3	7	10.6	15	23.5	26.5	30.9	43.5	50.4
Avg	7.5	7.9	9.8	13.6	19.8	29.5	33.8	39.5	50.1	60.1
bvEquity	1.72	1.89	2.16	2.59	3.06	3.66	4.36	5.10	5.82	6.58
SBUX	9.3	4.3	4.3	6.0	7.1	8.3	9.0	10.0	13.9	14.2
High	18.30	10.50	12.00	16.60	23.30	31.00	41.30	42.10	64.00	61.80
Low	9.9	3.5	4.1	10.6	15.4	21.5	26.3	34	39.3	50.8
Avg	14.1	7.0	8.1	13.6	19.4	26.3	33.8	38.1	51.7	56.3
bvEquity	1.51	1.62	1.87	2.27	2.72	3.18	3.76	3.82	3.72	3.98
SRCL	6.5	7.0	5.7	5.8	6.2	5.3	5.6	5.7	5.7	4.2
High	62.60	66.10	58.30	82.20	95.70	96.00	121.60	134.10	151.60	128.90
Low	36.5	46.4	44.4	50.6	73.1	75.8	93.2	108.6	110.6	71.5
Avg	49.6	56.3	51.4	66.4	84.4	85.9	107.4	121.4	131.1	100.2
bvEquity	7.62	8.02	8.99	11.40	13.58	16.21	19.20	21.40	22.85	23.78
SYK	5.6	4.1	2.8	2.9	2.8	2.5	2.8	3.7	4.3	4.4
High	76.90	74.90	52.70	59.70	65.20	57.20	75.60	98.20	105.30	123.60
Low	54.9	35.4	30.8	42.7	43.7	49.4	55.2	74	89.8	86.7
Avg	65.9	55.2	41.8	51.2	54.5	53.3	65.4	86.1	97.6	105.2
bvEquity	11.68	13.37	15.11	17.46	19.25	21.38	23.27	23.32	22.76	24.15

Southern California Edison Company
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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
SYY	6.5	5.0	4.2	4.8	4.0	3.7	4.4	4.2	4.3	6.4
High	36.70	35.00	29.50	32.00	32.80	32.40	43.40	41.20	42.00	57.10
Low	29.9	20.7	19.4	27	25.1	27	30.5	34.1	35.4	38.8
Avg	33.3	27.9	24.5	29.5	29.0	29.7	37.0	37.7	38.7	48.0
bvEquity	5.15	5.52	5.76	6.18	7.23	7.97	8.43	8.93	8.92	7.54
TGT	3.2	2.3	2.0	2.6	2.3	2.3	2.6	2.8	3.5	3.6
High	70.80	59.60	51.80	60.70	61.00	65.80	73.50	76.60	85.80	84.10
Low	48.8	25.6	25	48.2	45.3	47.3	58	54.7	68.1	65.5
Avg	59.8	42.6	38.4	54.5	53.2	56.6	65.8	65.7	77.0	74.8
bvEquity	18.44	18.46	19.42	21.31	22.82	24.65	25.65	23.75	21.69	20.61
TJX	5.8	5.5	4.9	5.6	6.5	8.4	9.6	10.0	11.0	11.1
High	16.20	18.80	20.30	24.30	32.80	46.70	64.10	69.80	76.90	83.60
Low	12.9	8.9	9.6	17.9	21.3	31.7	42.4	51.9	63.5	65.6
Avg	14.6	13.9	15.0	21.1	27.1	39.2	53.3	60.9	70.2	74.6
bvEquity	2.51	2.54	3.06	3.76	4.14	4.68	5.53	6.12	6.36	6.74
UNH	3.3	2.2	1.3	1.5	1.8	1.9	2.0	2.6	3.2	3.6
High	59.50	57.90	33.30	38.10	53.50	60.80	75.90	104.00	126.20	164.00
Low	45.8	14.5	16.2	27.1	36.4	49.8	51.4	69.6	95	107.5
Avg	52.7	36.2	24.8	32.6	45.0	55.3	63.7	86.8	110.6	135.8
bvEquity	15.74	16.66	18.94	22.18	25.11	28.52	31.57	33.28	34.71	37.75
VAR	7.1	6.7	4.0	5.0	5.5	5.0	4.8	5.2	5.0	5.0
High	53.20	65.80	47.80	71.00	72.20	72.60	80.70	89.90	96.70	106.70
Low	37.3	33.1	27.1	35.5	48.7	52.9	63.1	76.7	71.1	73.2
Avg	45.3	49.5	37.5	53.3	60.5	62.8	71.9	83.3	83.9	90.0
bvEquity	6.36	7.37	9.33	10.64	10.94	12.44	14.95	16.13	16.81	18.02
VZ	2.4	2.1	2.1	2.2	2.8	3.5	4.6	8.0	12.7	10.5
High	46.20	44.30	34.80	36.00	40.30	48.80	54.30	53.70	50.90	56.90
Low	35.6	23.1	26.1	26	32.3	36.8	41.5	45.1	38.1	43.8
Avg	40.9	33.7	30.5	31.0	36.3	42.8	47.9	49.4	44.5	50.4
bvEquity	17.15	16.15	14.68	14.16	13.17	12.15	10.49	6.17	3.50	4.78
WBA	4.0	2.5	2.3	2.2	2.4	1.8	2.5	3.2	3.4	3.1
High	49.10	39.00	40.70	40.20	47.10	37.80	60.90	78.00	97.30	102.80
Low	35.8	21.3	21.4	26.3	30.3	28.5	37.1	55.3	73	71.5
Avg	42.5	30.2	31.1	33.3	38.7	33.2	49.0	66.7	85.2	87.2
bvEquity	10.62	12.11	13.78	14.94	16.02	18.01	19.94	21.09	24.98	28.14
WMT	3.0	3.3	2.9	2.7	2.7	3.1	3.2	3.3	2.9	2.7
High	51.40	63.80	57.50	56.30	60.00	77.60	81.40	88.10	91.00	75.20
Low	42.1	43.1	46.3	47.8	48.3	57.2	67.7	72.3	56.3	60.2
Avg	46.8	53.5	51.9	52.1	54.2	67.4	74.6	80.2	73.7	67.7
bvEquity	15.59	16.45	17.66	19.09	20.18	21.95	23.32	24.41	25.35	25.50
WM	3.2	2.7	2.3	2.6	2.6	2.5	3.1	3.7	4.1	5.1
High	41.20	39.30	34.20	37.30	39.70	36.30	46.40	51.90	55.90	71.80
Low	32.4	24.5	22.1	31.1	27.8	30.8	33.7	40.3	45.9	50.4
Avg	36.8	31.9	28.2	34.2	33.8	33.6	40.1	46.1	50.9	61.1
bvEquity	11.62	11.81	12.48	13.06	13.18	13.44	12.99	12.54	12.37	12.01

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	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
WAT	13.9	9.1	5.9	6.6	6.8	5.6	5.2	4.8	5.2	5.1
High	81.50	81.80	63.10	81.00	100.00	94.50	108.90	117.70	137.40	162.50
Low	48.6	32.2	30	56	70.9	73	85	93.6	111.8	112
Avg	65.1	57.0	46.6	68.5	85.5	83.8	97.0	105.7	124.6	137.3
bvEquity	4.69	6.28	7.89	10.33	12.57	14.96	18.61	21.79	24.03	27.02
WFM	4.3	2.3	1.9	3.1	4.0	4.6	5.1	4.5	4.0	3.0
High	26.80	21.20	17.20	25.90	37.20	50.90	65.60	57.80	57.60	35.60
Low	18	3.5	4.5	13.4	23.9	34.7	40.7	36.1	28.7	27.7
Avg	22.4	12.4	10.9	19.7	30.6	42.8	53.2	47.0	43.2	31.7
bvEquity	5.27	5.31	5.58	6.35	7.63	9.31	10.33	10.50	10.69	10.47
GWW	3.2	2.9	2.8	3.7	4.4	4.7	5.1	5.1	5.3	6.2
High	98.60	94.00	102.50	139.10	193.20	221.80	276.40	269.70	257.00	240.70
Low	68.8	58.9	59.9	96.1	124.3	172.5	201.5	223.9	189.6	176.9
Avg	83.7	76.5	81.2	117.6	158.8	197.2	239.0	246.8	223.3	208.8
bvEquity	26.15	26.80	29.01	31.90	35.96	41.91	46.62	47.98	42.07	33.56

	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Median	4.2	3.4	3.0	3.2	3.2	3.4	3.7	4.2	4.7	4.9

Southern California Edison Company
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Projected ROE

	Ticker	PE Ratios									
	Symbols	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
3M COMPANY	MMM	15	14.6	14.1	14.5	14.5	14.1	17	19.1	20.6	20.6
AMPHENOL CORP.	APH	19.1	16.7	18.5	16	16.4	17	20.1	21.6	22.8	21.7
APPLE INC.	AAPL	26.3	30.4	19.2	15.2	12.4	12	12.3	13	12.8	12.6
AT&T INC.	T	14.2	15.4	12.1	11.7	13.4	14.5	14.2	13.8	12.6	13.8
AUTO. DATA PROC.	ADP	26	20.1	16	17.2	18.7	18.7	21.8	24.5	29	26
BALL CORP.	BLL	14.2	12.2	11.2	9.6	13.6	16	16.9	18.3	34.8	45.2
BAXTER INT'L	BAX	19.6	18.2	14.2	12.6	12.6	12.8	14.9	14.7	40.5	22.4
BECTON, D'SON.	BDX	19.5	19	13.7	14.9	14.5	14.1	15.6	18.1	19.5	18.4
BROWN-FORMAN `B'	BFB	19.7	17.8	16.1	17.9	21.4	24.1	24.7	28.4	28.8	27.6
CAMPBELL SOUP	CPB	19.7	16.6	14.6	14.1	13.7	13.4	16	17.1	17.1	19.3
CARDINAL HEALTH	CAH	20	15.8	17.4	14.6	14.3	13.8	13	18.5	22.6	19.1
CERNER CORP.	CERN	36.2	21.1	25.7	30	33.5	33.1	37.3	34.8	31.5	24.6
C.H. ROBINSON	CHRW	27.2	25.9	24.6	27	28.1	16.7	22.3	20.6	19.5	19.8
CHURCH & DWIGHT	CHD	19.9	19.8	15.8	16.6	18.4	21.2	22.3	23.1	26	26.5
CIGNA CORPORATION	CI	12.8	10.5	6.2	7.4	8.6	7.8	10.6	12.1	15.5	16.4
CINTAS CORP.	CTAS	18.9	15.7	13.8	17.9	16.6	14.9	16.6	19.4	21.4	21.5
COCA-COLA	KO	21	17.8	16.6	16.2	17.4	18.8	19.1	20	20.6	22.8
COMCAST CORP.	CMCSA	34.1	20.9	11.8	14.3	14.9	14	16.9	18.2	18.1	18.2
CONAGRA BRANDS	CAG	18.2	22.8	12	12.8	13.2	13.9	13.8	14.9	15.8	20.3
CONSTELLATION	STZ	15.9	11.2	8.5	9.5	8.7	13.6	18.4	20.3	23.6	23.3
COSTCO WHOLESALE	COST	21	23.1	19.5	19.9	22.1	21.9	23.4	25.1	26.7	29
BARD (C.R.), INC.	BCR	21.7	20.5	15.3	14.8	15	14.9	19.6	17.6	19.8	20.6
DEERE & CO.	DE	14.5	16.1	14	13.7	12.5	10.4	9.5	10.1	15.2	16.7
DENTSPLY SIRONA	XRAY	22.5	19.6	16.5	17.2	17.8	17.2	18.4	19.1	20.6	21.7
EDWARDS LIFESCI.	EW	23.1	20.9	21.8	30.8	39.3	32.5	23.6	26.3	31	34.2
Lilly (Eli)	LLY	15.7	11.4	7.8	7.4	8.4	12.9	12.7	22.2	22.9	21.7
EQUIFAX, INC.	EFX	17.4	13.2	11.5	13.7	14	15.6	17	19	21.9	21.8
EXPEDITORS INT'L	EXPD	36.9	28.7	28.7	26.3	26.6	25.2	24.3	22.1	19.7	20.9
EXPRESS SCRIPTS.	ESRX	21.8	21.1	21.7	22	20.2	31.1	26.7	27.9	24.2	16.6
EXXON MOBIL	XOM	11.4	9.5	17.8	10.5	9.5	10.7	12.3	12.8	21.5	45.8
FISERV, INC.	FISV	19.9	14.2	11.8	12.6	13	13.7	15.8	18.4	21.7	22.9
FLIR SYSTEMS, INC.	FLIR	26.5	26.1	17.2	18.3	19	14.9	22.7	24	19.2	21
FOOT LOCKER	FL	42.7	18.4	19.6	13.7	12.1	12.6	12.3	14	16.9	13.4
GEN'L. DYNAMICS	GD	16	12.9	9.2	9.9	9.9	10.4	11.3	15.2	15.5	14.8
GENERAL MILLS	GIS	17.6	16.5	15.2	14.3	14.7	15.1	15.7	17.8	18.6	20
GENUINE PARTS	GPC	16.4	13.9	13.8	14.4	15.1	15.2	18.6	19.3	19.5	20.8
HASBRO, INC.	HAS	14.2	15.9	10.7	15	14.8	12.8	16.3	17.1	20	18.1
SCHEIN (HENRY) INC.	HSIC	21.6	17.7	14.6	15.9	16.9	17.6	20.2	22	25.2	26.4
HERSHEY CO. (THE)	HSY	23.2	19.5	16.9	17.9	19.8	20.9	24.2	24.5	23	21.9
HOME DEPOT	HD	15.4	14.3	15.3	15.6	15	17.9	20.2	19.1	22.1	20.3

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	Ticker Symbols	PE Ratios 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
HORMEL FOODS	HRL	17.3	18.2	13	13.7	15.7	15.6	19.8	21.3	21.6	23.4
HUMANA INC.	HUM	13.3	11	5.5	7.7	8.8	10.2	9.8	16.3	22.7	18.7
INT'L BUS. MACH.	IBM	14.8	12.3	10.9	11.4	13.1	13.7	13	11.7	11.4	12.1
International Flavors & Fragrances Inc	IFF	18.4	14.3	12.7	14.4	15.7	14.8	17.7	19.1	21.6	22.6
SMUCKER (J.M.) CO.	SJM	16.9	12	12.5	13.2	16.2	16	18.3	19.6	20.1	21
JOHNSON & JOHNSON	JNJ	15.4	14.3	12.5	13.1	12.7	13.1	15.6	17.7	18.2	19.1
KELLOGG CO.	K	19	17	14.5	15.7	15.8	15.3	16.5	16.5	18.7	20.5
THE KROGER CO.	KR	16.4	14.1	12.5	12.4	11.8	9.1	12.9	14.5	18.2	16.4
LAB. CORP. AMER.	LH	18	15.4	13.4	13.9	14	13	13.8	14.8	15.3	14.3
MATTEL, INC.	MAT	15.9	17.5	11.2	12.1	12.1	13.5	16.7	24.3	23.3	34
McCORMICK	MKC	19.4	17.2	13.7	14.8	17.1	18.7	22	20.6	22.5	25.1
MEDTRONIC, PLC.	MDT	19.4	14.1	12.3	11	10.7	11.3	14.6	15.5	14.6	15
MERCK & CO.	MRK	34.1	10.2	9.1	10.5	9.1	10.8	13.3	16.4	15.8	15.2
MOLSON COORS	TAP	16.8	18	11.3	12.6	12.2	17.5	16.3	24.3	40.8	32.7
MONSANTO COMPANY	MON	28	32.3	18.7	28.5	22.6	20.7	21.6	21.7	20	32.5
NIKE, INC. `B'	NKE	16.5	17.8	15.3	16.4	18.2	20.4	19.4	24.2	24.4	27.5
NORTHROP GRUMMAN	NOC	15.2	12.4	9.9	10.5	8.3	8.2	10.4	12.9	16.1	17.4
PATTERSON COS.	PDCO	22.7	21.2	14.8	14.9	15.7	16.2	17.2	19.4	19.8	24.2
PAYCHEX, INC.	PAYX	28.4	24.6	19.2	22.2	20.7	19.6	21.4	24.1	24.8	24
PEPSICO, INC.	PEP	20.5	20.5	14.7	16.5	16.4	17.4	18.4	20.8	20.7	21.4
PERRIGO CO. PLC	PRGO	20.7	18.9	15.9	15.4	19.3	22.4	24.2	22.2	22.6	20.7
PFIZER INC.	PFE	11.5	16.4	12.8	16.3	17.6	18.4	17.6	21.5	30.3	28.1
PROCTER & GAMBLE	PG	20.5	18.6	16.4	17	16	16.7	17.8	19	20.9	21.4
QUALCOMM INC.	QCOM	19.9	19.5	21	16.5	16.4	15.9	14.2	14.3	14.5	12.1
QUEST DIAGNOST.	DGX	18.6	15.1	13.7	13	12.2	13.6	14.8	14.5	14.8	15.2
RAYTHEON	RTN	17.3	14.8	9.4	10.6	8.9	9.5	11.7	14	16.2	18
REPUBLIC SERVICES	RSG	18.5	15.2	16	17.2	14.9	15.7	16.9	18.7	20.1	22.3
RESMED INC.	RMD	33.4	29.5	20.2	21.8	22.3	17.2	20	20.3	23.4	22.7
ROSS STORES, INC.	ROST	15.5	14.1	11.6	12	14.1	17.2	17.4	17	20.3	21.4
STARBUCKS CORP.	SBUX	36.3	26.4	16	18.7	22.8	27.5	26.5	27.9	30.2	30.4
STERICYCLE INC.	SRCL	33.1	32.2	24.2	25.1	29.8	27	29.2	27.8	30.5	21.6
STRYKER CORP.	SYK	27.9	21.8	15.1	15.7	14.8	15.8	25.9	35.2	25.2	25.4
SYSCO CORP.	SYY	20.8	17.2	14.3	13.8	15	15.1	19.2	22.2	20.8	20.3
TARGET CORP.	TGT	18	16.2	12.8	13.9	11.9	13.7	20.7	14.7	16.6	14.6
TJX COMPANIES	TJX	14.8	14.6	11.5	13.2	14	16.5	18.9	19	20.8	21.6
UNITEDHEALTH GRP.	UNH	15.3	10.9	8.1	8	9.8	10.4	11.9	14.7	19.4	16.8
VARIAN MEDICAL	VAR	25	22.3	13.9	17.2	19.1	16.6	17.5	21.1	21.3	19.8
VERIZON	VZ	17.6	13.7	12.7	13.8	17.1	18.1	12.2	14.5	11.8	13.3
WALGREENS BOOTS	WBA	22.2	17.1	13.9	15.9	14.8	13.2	16.3	21.8	20.2	18
WAL-MART STORES	WMT	14.9	16.2	13.9	13.1	12.4	13.5	14.9	15.4	15.5	16.2
WASTE MANAGEMENT	WM	17.7	15.4	14.6	16.3	16.4	16.2	18.9	18.2	20.4	21.3
WATERS CORP.	WAT	24.3	17.7	14.4	16.7	17.9	16	18.8	21.1	22.3	21.7
WHOLE FOODS MKT.	WFM	35.6	40.4	20.4	23.9	29.3	32.6	33.1	31.2	27.4	20.1
GRAINGER (W.W.)	GWW	17.2	13.4	16	16.4	16.8	21.1	21.5	20.3	19	19.1

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	Ticker Symbols	M/B Ratios 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
3M COMPANY	MMM	5.64	4.38	3.89	3.99	3.77	3.72	4.51	6.20	7.64	8.69
AMPHENOL CORP.	APH	6.39	4.72	3.83	3.94	3.70	3.86	4.66	5.31	5.42	5.07
APPLE INC.	AAPL	10.05	6.93	5.36	6.23	5.48	5.35	3.65	4.92	5.61	4.58
AT&T INC.	T	1.55	1.77	1.51	1.47	1.61	1.96	2.10	2.02	1.84	1.93
AUTO. DATA PROC.	ADP	4.69	3.92	3.72	3.39	4.27	4.46	5.56	5.88	6.40	8.96
BALL CORP.	BLL	4.05	3.35	3.13	3.38	4.28	5.39	5.89	7.40	8.27	5.08
BAXTER INT'L	BAX	5.22	5.66	4.82	4.39	4.81	4.86	4.86	4.70	3.41	2.68
BECTON, D'SON.	BDX	4.63	3.96	3.34	3.35	3.46	3.50	4.03	4.74	4.75	4.46
BROWN-FORMAN `B'	BFB	5.28	4.40	3.63	4.49	5.01	7.07	8.04	9.20	11.62	12.70
CAMPBELL SOUP	CPB	9.83	9.56	10.56	14.60	10.62	10.89	12.33	9.53	10.20	12.60
CARDINAL HEALTH	CAH	3.23	2.16	1.41	1.77	2.69	2.34	3.05	4.01	4.38	3.87
CERNER CORP.	CERN	4.26	2.99	3.37	4.03	4.80	4.91	5.67	5.85	6.03	4.91
C.H. ROBINSON	CHRW	8.67	8.24	7.64	9.64	10.14	7.49	7.77	9.47	8.95	8.17
CHURCH & DWIGHT	CHD	3.37	3.20	2.59	2.66	2.92	3.54	3.84	4.39	5.37	5.92
CIGNA CORPORATION	CI	3.16	2.15	1.54	1.54	1.62	1.44	1.98	2.28	3.09	2.63
CINTAS CORP.	CTAS	2.80	1.88	1.62	1.65	1.85	2.40	2.89	3.69	4.72	5.78
COCA-COLA	KO	6.59	5.80	4.93	4.74	4.84	5.16	5.37	5.66	6.26	7.71
COMCAST CORP.	CMCSA	2.13	1.28	1.00	1.21	1.39	1.72	2.33	2.66	2.72	2.81
CONAGRA BRANDS	CAG	2.74	1.88	1.74	2.17	2.17	2.45	2.86	2.62	3.43	4.33
CONSTELLATION	STZ	1.76	1.60	1.39	1.56	1.53	1.92	2.47	3.12	3.91	4.45
COSTCO WHOLESALE	COST	3.14	2.91	2.25	2.64	3.01	3.29	4.21	4.84	5.48	5.94
BARD (C.R.), INC.	BCR	4.93	4.48	3.68	4.06	4.83	4.32	4.71	5.86	8.34	9.63
DEERE & CO.	DE	4.24	3.89	3.03	5.07	5.05	4.63	3.88	3.24	3.58	4.17
DENTSPLY SIRONA	XRAY	4.19	3.37	2.53	2.60	2.64	2.67	2.71	2.90	3.40	2.29
EDWARDS LIFESCI.	EW	3.54	3.56	3.91	5.92	6.64	7.24	5.72	5.70	6.65	8.08
Lilly (Eli)	LLY	5.06	4.79	4.78	3.68	3.36	3.75	3.69	4.23	5.96	5.78
EQUIFAX, INC.	EFX	4.65	2.80	2.21	2.40	2.42	3.05	3.45	3.89	5.09	5.49
EXPEDITORS INT'L	EXPD	8.61	6.05	4.50	5.77	5.35	4.24	4.06	4.26	4.94	4.95
EXPRESS SCRIPTS.	ESRX	15.48	17.92	7.67	7.04	8.00	3.32	2.18	2.70	3.05	2.90
EXXON MOBIL	XOM	3.87	3.37	3.14	2.45	2.50	2.46	2.42	2.34	1.94	2.05
FISERV, INC.	FISV	3.57	2.68	2.21	2.53	2.51	2.83	3.69	4.59	6.54	8.35
FLIR SYSTEMS, INC.	FLIR	6.75	6.59	3.77	3.29	3.00	2.13	2.53	2.86	2.53	2.62
FOOT LOCKER	FL	1.24	0.80	0.81	1.22	1.56	2.06	2.21	2.74	3.52	3.32
GEN'L. DYNAMICS	GD	3.10	2.59	1.82	1.98	1.81	1.96	2.19	3.13	4.06	4.26
GENERAL MILLS	GIS	3.63	3.61	3.46	4.47	4.16	3.98	4.60	4.85	5.64	7.61
GENUINE PARTS	GPC	3.12	2.46	2.08	2.59	3.04	3.28	3.63	4.27	4.39	4.30
HASBRO, INC.	HAS	3.08	3.24	2.48	3.44	3.50	3.16	3.68	4.34	5.41	5.44
SCHEIN (HENRY) INC.	HSIC	2.99	2.31	1.99	2.27	2.51	2.60	3.17	3.76	4.20	4.64
HERSHEY CO. (THE)	HSY	17.03	19.05	15.92	12.33	14.04	15.97	14.74	14.29	17.32	24.12
HOME DEPOT	HD	2.92	2.29	2.14	2.76	3.03	4.56	6.88	11.11	18.71	28.77

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	Ticker Symbols	M/B Ratios 2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
HORMEL FOODS	HRL	2.67	2.35	2.26	2.65	2.89	2.82	3.33	3.74	4.54	4.93
HUMANA INC.	HUM	3.15	2.20	1.07	1.39	1.61	1.49	1.48	1.94	2.66	2.60
INT'L BUS. MACH.	IBM	5.33	6.55	7.81	7.26	9.42	11.35	10.09	10.41	11.51	8.42
International Flavors & Fragrances Inc	IFF	5.67	4.88	3.98	4.31	4.50	4.14	4.74	5.13	5.71	5.96
SMUCKER (J.M.) CO.	SJM	1.72	1.26	1.12	1.31	1.52	1.68	2.06	1.79	1.86	2.28
JOHNSON & JOHNSON	JNJ	4.46	4.08	3.31	3.15	3.02	3.04	3.35	3.81	3.70	4.25
KELLOGG CO.	K	9.04	9.62	9.20	8.71	9.77	8.90	7.53	7.11	9.69	13.53
THE KROGER CO.	KR	3.82	3.45	2.99	2.69	2.99	3.15	3.67	4.61	5.56	4.97
LAB. CORP. AMER.	LH	4.65	4.29	3.64	3.55	3.49	3.24	3.33	3.16	2.88	2.33
MATTEL, INC.	MAT	3.82	2.68	2.43	3.15	3.41	3.93	4.53	4.17	3.07	3.96
McCORMICK	MKC	4.70	4.23	3.56	3.94	4.09	4.66	4.92	4.83	5.81	7.13
MEDTRONIC, PLC.	MDT	5.18	3.94	2.79	2.74	2.34	2.31	2.64	2.27	1.81	2.12
MERCK & CO.	MRK	6.31	4.86	2.09	1.97	1.89	2.39	2.64	3.27	3.29	3.70
MOLSON COORS	TAP	1.32	1.31	1.16	1.12	1.07	1.02	1.12	1.50	2.02	2.17
MONSANTO COMPANY	MON	6.42	6.79	4.50	3.55	3.42	3.76	4.60	5.81	6.62	7.83
NIKE, INC. `B'	NKE	4.43	3.80	3.11	4.02	4.11	4.61	5.52	6.81	8.33	7.78
NORTHROP GRUMMAN	NOC	1.51	1.32	1.17	1.40	1.39	1.58	2.02	3.07	5.01	7.09
PATTERSON COS.	PDCO	3.78	2.99	2.07	2.32	2.49	2.55	2.88	3.00	3.28	3.11
PAYCHEX, INC.	PAYX	8.78	7.20	7.56	7.57	7.37	7.45	8.34	9.03	9.80	10.55
PEPSICO, INC.	PEP	7.02	7.01	5.73	5.14	4.85	4.90	5.15	6.45	9.01	12.68
PERRIGO CO. PLC	PRGO	3.54	3.91	2.97	4.85	5.89	5.81	5.74	3.31	2.58	2.03
PFIZER INC.	PFE	2.55	2.12	1.56	1.56	1.77	2.13	2.50	2.61	2.98	3.24
PROCTER & GAMBLE	PG	3.37	2.97	2.46	2.47	2.76	2.77	3.25	3.38	3.25	3.73
QUALCOMM INC.	QCOM	4.67	4.16	3.53	3.26	3.65	3.42	3.24	3.33	2.75	2.70
QUEST DIAGNOST.	DGX	3.26	2.74	2.55	2.23	2.26	2.38	2.17	2.08	2.38	2.30
RAYTHEON	RTN	2.15	2.10	1.80	1.95	1.78	2.20	2.41	3.01	3.47	3.93
REPUBLIC SERVICES	RSG	4.27	2.09	1.15	1.44	1.40	1.34	1.50	1.65	1.89	2.21
RESMED INC.	RMD	4.35	3.10	2.92	3.83	2.95	2.96	4.38	4.15	5.21	5.21
ROSS STORES, INC.	ROST	4.33	4.16	4.55	5.26	6.47	8.05	7.74	7.75	8.62	9.14
STARBUCKS CORP.	SBUX	9.34	4.32	4.30	6.00	7.13	8.25	8.99	9.97	13.88	14.16
STERICYCLE INC.	SRCL	6.51	7.02	5.71	5.83	6.22	5.30	5.59	5.67	5.74	4.21
STRYKER CORP.	SYK	5.64	4.13	2.76	2.93	2.83	2.49	2.81	3.69	4.29	4.35
SYSCO CORP.	SYY	6.47	5.05	4.24	4.77	4.01	3.73	4.38	4.22	4.34	6.36
TARGET CORP.	TGT	3.24	2.31	1.98	2.56	2.33	2.29	2.56	2.76	3.55	3.63
TJX COMPANIES	TJX	5.81	5.45	4.89	5.62	6.53	8.38	9.63	9.95	11.04	11.08
UNITEDHEALTH GRP.	UNH	3.34	2.17	1.31	1.47	1.79	1.94	2.02	2.61	3.19	3.60
VARIAN MEDICAL	VAR	7.12	6.71	4.02	5.00	5.53	5.05	4.81	5.16	4.99	4.99
VERIZON	VZ	2.38	2.09	2.07	2.19	2.76	3.52	4.57	8.01	12.73	10.53
WALGREENS BOOTS	WBA	4.00	2.49	2.25	2.23	2.42	1.84	2.46	3.16	3.41	3.10
WAL-MART STORES	WMT	3.00	3.25	2.94	2.73	2.68	3.07	3.20	3.29	2.91	2.66
WASTE MANAGEMENT	WM	3.17	2.70	2.26	2.62	2.56	2.50	3.08	3.68	4.11	5.09
WATERS CORP.	WAT	13.88	9.08	5.90	6.63	6.80	5.60	5.21	4.85	5.19	5.08
WHOLE FOODS MKT.	WFM	4.25	2.33	1.94	3.10	4.00	4.60	5.15	4.47	4.04	3.02
GRAINGER (W.W.)	GWW	3.20	2.85	2.80	3.69	4.42	4.70	5.13	5.14	5.31	6.22

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	Ticker Symbols	Projected Earnings Per Share 2017	2018	2019	2020	2021	2022
3M COMPANY	MMM	$ 8.90	$ 9.90	$ 11.01	$ 12.25	$ 13.63	$ 15.16
AMPHENOL CORP.	APH	$ 3.00	$ 3.30	$ 3.63	$ 4.00	$ 4.40	$ 4.85
APPLE INC.	AAPL	$ 9.10	$ 10.51	$ 12.13	$ 14.00	$ 16.16	$ 18.66
AT&T INC.	T	$ 2.90	$ 3.15	$ 3.41	$ 3.70	$ 4.01	$ 4.35
AUTO. DATA PROC.	ADP	$ 3.65	$ 4.18	$ 4.80	$ 5.50	$ 6.31	$ 7.23
BALL CORP.	BLL	$ 1.95	$ 2.16	$ 2.39	$ 2.65	$ 2.94	$ 3.25
BAXTER INT'L	BAX	$ 2.25	$ 2.53	$ 2.85	$ 3.20	$ 3.60	$ 4.05
BECTON, D'SON.	BDX	$ 9.45	$ 10.30	$ 11.23	$ 12.25	$ 13.36	$ 14.56
BROWN-FORMAN `B'	BFB	$ 2.00	$ 2.25	$ 2.53	$ 2.85	$ 3.21	$ 3.61
CAMPBELL SOUP	CPB	$ 3.05	$ 3.22	$ 3.41	$ 3.60	$ 3.80	$ 4.02
CARDINAL HEALTH	CAH	$ 4.30	$ 5.23	$ 6.37	$ 7.75	$ 9.43	$ 11.48
CERNER CORP.	CERN	$ 2.51	$ 2.79	$ 3.10	$ 3.45	$ 3.84	$ 4.26
C.H. ROBINSON	CHRW	$ 3.70	$ 4.08	$ 4.49	$ 4.95	$ 5.45	$ 6.01
CHURCH & DWIGHT	CHD	$ 1.92	$ 2.08	$ 2.26	$ 2.45	$ 2.66	$ 2.88
CIGNA CORPORATION	CI	$ 9.25	$ 10.99	$ 13.05	$ 15.50	$ 18.41	$ 21.87
CINTAS CORP.	CTAS	$ 4.60	$ 5.03	$ 5.49	$ 6.00	$ 6.56	$ 7.16
COCA-COLA	KO	$ 1.85	$ 2.06	$ 2.29	$ 2.55	$ 2.84	$ 3.16
COMCAST CORP.	CMCSA	$ 2.00	$ 2.29	$ 2.62	$ 3.00	$ 3.43	$ 3.93
CONAGRA BRANDS	CAG	$ 1.74	$ 1.91	$ 2.10	$ 2.30	$ 2.52	$ 2.77
CONSTELLATION	STZ	$ 8.00	$ 9.00	$ 10.13	$ 11.40	$ 12.83	$ 14.44
COSTCO WHOLESALE	COST	$ 5.75	$ 6.55	$ 7.46	$ 8.50	$ 9.68	$ 11.03
BARD (C.R.), INC.	BCR	$ 11.50	$ 12.70	$ 14.03	$ 15.50	$ 17.12	$ 18.91
DEERE & CO.	DE	$ 4.75	$ 5.86	$ 7.22	$ 8.90	$ 10.97	$ 13.53
DENTSPLY SIRONA	XRAY	$ 2.75	$ 3.18	$ 3.68	$ 4.25	$ 4.91	$ 5.68
EDWARDS LIFESCI.	EW	$ 3.50	$ 4.07	$ 4.73	$ 5.50	$ 6.39	$ 7.43
Lilly (Eli)	LLY	$ 4.10	$ 4.68	$ 5.34	$ 6.10	$ 6.96	$ 7.95
EQUIFAX, INC.	EFX	$ 6.05	$ 6.70	$ 7.41	$ 8.20	$ 9.07	$ 10.04
EXPEDITORS INT'L	EXPD	$ 2.35	$ 2.68	$ 3.06	$ 3.50	$ 4.00	$ 4.56
EXPRESS SCRIPTS.	ESRX	$ 5.10	$ 5.73	$ 6.45	$ 7.25	$ 8.15	$ 9.17
EXXON MOBIL	XOM	$ 4.05	$ 5.19	$ 6.64	$ 8.50	$ 10.88	$ 13.93
FISERV, INC.	FISV	$ 5.10	$ 5.53	$ 6.00	$ 6.50	$ 7.05	$ 7.64
FLIR SYSTEMS, INC.	FLIR	$ 1.85	$ 1.99	$ 2.14	$ 2.30	$ 2.47	$ 2.66
FOOT LOCKER	FL	$ 5.20	$ 5.70	$ 6.25	$ 6.85	$ 7.51	$ 8.23
GEN'L. DYNAMICS	GD	$ 9.80	$ 10.61	$ 11.50	$ 12.45	$ 13.48	$ 14.60
GENERAL MILLS	GIS	$ 3.08	$ 3.29	$ 3.51	$ 3.75	$ 4.00	$ 4.28
GENUINE PARTS	GPC	$ 4.80	$ 5.44	$ 6.17	$ 7.00	$ 7.94	$ 9.00
HASBRO, INC.	HAS	$ 5.00	$ 5.54	$ 6.14	$ 6.80	$ 7.53	$ 8.35
SCHEIN (HENRY) INC.	HSIC	$ 7.25	$ 7.93	$ 8.68	$ 9.50	$ 10.40	$ 11.38
HERSHEY CO. (THE)	HSY	$ 4.85	$ 5.28	$ 5.74	$ 6.25	$ 6.80	$ 7.40
HOME DEPOT	HD	$ 7.25	$ 8.04	$ 8.92	$ 9.90	$ 10.98	$ 12.19

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	Ticker Symbols	Projected Earnings Per Share 2017	2018	2019	2020	2021	2022
HORMEL FOODS	HRL	$ 1.65	$ 1.90	$ 2.18	$ 2.50	$ 2.87	$ 3.30
HUMANA INC.	HUM	$ 11.30	$ 12.27	$ 13.31	$ 14.45	$ 15.68	$ 17.02
INT'L BUS. MACH.	IBM	$ 11.95	$ 12.60	$ 13.28	$ 14.00	$ 14.76	$ 15.56
International Flavors & Fragrances Inc	IFF	$ 5.80	$ 6.51	$ 7.31	$ 8.20	$ 9.20	$ 10.33
SMUCKER (J.M.) CO.	SJM	$ 6.75	$ 7.33	$ 7.96	$ 8.65	$ 9.40	$ 10.21
JOHNSON & JOHNSON	JNJ	$ 6.45	$ 7.44	$ 8.58	$ 9.90	$ 11.42	$ 13.17
KELLOGG CO.	K	$ 3.95	$ 4.40	$ 4.90	$ 5.45	$ 6.07	$ 6.75
THE KROGER CO.	KR	$ 2.00	$ 2.25	$ 2.53	$ 2.85	$ 3.21	$ 3.61
LAB. CORP. AMER.	LH	$ 9.45	$ 10.47	$ 11.60	$ 12.85	$ 14.24	$ 15.77
MATTEL, INC.	MAT	$ 0.90	$ 1.22	$ 1.66	$ 2.25	$ 3.05	$ 4.14
McCORMICK	MKC	$ 4.10	$ 4.52	$ 4.99	$ 5.50	$ 6.07	$ 6.69
MEDTRONIC, PLC.	MDT	$ 5.65	$ 5.98	$ 6.33	$ 6.70	$ 7.09	$ 7.51
MERCK & CO.	MRK	$ 3.85	$ 4.20	$ 4.58	$ 5.00	$ 5.46	$ 5.95
MOLSON COORS	TAP	$ 4.50	$ 4.87	$ 5.27	$ 5.70	$ 6.17	$ 6.67
MONSANTO COMPANY	MON	$ 4.60	$ 5.35	$ 6.23	$ 7.25	$ 8.44	$ 9.82
NIKE, INC. `B'	NKE	$ 2.51	$ 3.00	$ 3.59	$ 4.30	$ 5.15	$ 6.16
NORTHROP GRUMMAN	NOC	$ 12.10	$ 13.59	$ 15.27	$ 17.15	$ 19.26	$ 21.64
PATTERSON COS.	PDCO	$ 2.10	$ 2.64	$ 3.31	$ 4.15	$ 5.21	$ 6.54
PAYCHEX, INC.	PAYX	$ 2.25	$ 2.52	$ 2.82	$ 3.15	$ 3.52	$ 3.94
PEPSICO, INC.	PEP	$ 5.15	$ 5.70	$ 6.32	$ 7.00	$ 7.75	$ 8.59
PERRIGO CO. PLC	PRGO	$ 4.40	$ 4.88	$ 5.41	$ 6.00	$ 6.65	$ 7.38
PFIZER INC.	PFE	$ 1.35	$ 1.61	$ 1.93	$ 2.30	$ 2.75	$ 3.28
PROCTER & GAMBLE	PG	$ 3.90	$ 4.55	$ 5.31	$ 6.20	$ 7.24	$ 8.45
QUALCOMM INC.	QCOM	$ 4.25	$ 4.96	$ 5.79	$ 6.75	$ 7.88	$ 9.19
QUEST DIAGNOST.	DGX	$ 5.55	$ 6.27	$ 7.08	$ 8.00	$ 9.04	$ 10.21
RAYTHEON	RTN	$ 7.45	$ 8.52	$ 9.75	$ 11.15	$ 12.75	$ 14.59
REPUBLIC SERVICES	RSG	$ 2.40	$ 2.70	$ 3.03	$ 3.40	$ 3.82	$ 4.29
RESMED INC.	RMD	$ 2.40	$ 2.85	$ 3.37	$ 4.00	$ 4.74	$ 5.62
ROSS STORES, INC.	ROST	$ 3.10	$ 3.40	$ 3.74	$ 4.10	$ 4.50	$ 4.94
STARBUCKS CORP.	SBUX	$ 2.10	$ 2.55	$ 3.09	$ 3.75	$ 4.55	$ 5.52
STERICYCLE INC.	SRCL	$ 4.70	$ 5.10	$ 5.53	$ 6.00	$ 6.51	$ 7.06
STRYKER CORP.	SYK	$ 5.10	$ 5.80	$ 6.60	$ 7.50	$ 8.53	$ 9.70
SYSCO CORP.	SYY	$ 2.45	$ 2.77	$ 3.14	$ 3.55	$ 4.02	$ 4.55
TARGET CORP.	TGT	$ 4.35	$ 4.84	$ 5.39	$ 6.00	$ 6.68	$ 7.43
TJX COMPANIES	TJX	$ 3.85	$ 4.48	$ 5.20	$ 6.05	$ 7.03	$ 8.18
UNITEDHEALTH GRP.	UNH	$ 9.80	$ 10.90	$ 12.13	$ 13.50	$ 15.02	$ 16.71
VARIAN MEDICAL	VAR	$ 3.00	$ 3.80	$ 4.81	$ 6.10	$ 7.73	$ 9.79
VERIZON	VZ	$ 3.75	$ 3.91	$ 4.08	$ 4.25	$ 4.43	$ 4.62
WALGREENS BOOTS	WBA	$ 5.00	$ 5.62	$ 6.32	$ 7.10	$ 7.98	$ 8.97
WAL-MART STORES	WMT	$ 4.35	$ 4.82	$ 5.33	$ 5.90	$ 6.53	$ 7.23
WASTE MANAGEMENT	WM	$ 3.15	$ 3.41	$ 3.69	$ 4.00	$ 4.33	$ 4.69
WATERS CORP.	WAT	$ 7.20	$ 7.46	$ 7.72	$ 8.00	$ 8.29	$ 8.58
WHOLE FOODS MKT.	WFM	$ 1.30	$ 1.49	$ 1.70	$ 1.95	$ 2.23	$ 2.56
GRAINGER (W.W.)	GWW	$ 11.00	$ 12.46	$ 14.12	$ 16.00	$ 18.13	$ 20.54

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	Ticker Symbols	Projected Book Value of Equity 2017	2018	2019	2020	2021	2022
3M COMPANY	MMM	$ 16.65	$ 18.52	$ 20.60	$ 20.35	$ 22.64	$ 25.18
AMPHENOL CORP.	APH	$ 12.90	$ 14.20	$ 15.63	$ 15.60	$ 17.17	$ 18.90
APPLE INC.	AAPL	$ 27.15	$ 31.34	$ 36.18	$ 46.65	$ 53.85	$ 62.17
AT&T INC.	T	$ 20.65	$ 22.40	$ 24.29	$ 27.50	$ 29.83	$ 32.35
AUTO. DATA PROC.	ADP	$ 9.45	$ 10.83	$ 12.42	$ 14.65	$ 16.80	$ 19.26
BALL CORP.	BLL	$ 17.25	$ 19.11	$ 21.16	$ 24.20	$ 26.81	$ 29.69
BAXTER INT'L	BAX	$ 16.60	$ 18.67	$ 20.99	$ 24.00	$ 26.99	$ 30.35
BECTON, D'SON.	BDX	$ 36.55	$ 39.85	$ 43.45	$ 40.00	$ 43.61	$ 47.55
BROWN-FORMAN `B'	BFB	$ 4.95	$ 5.57	$ 6.27	$ 6.55	$ 7.37	$ 8.29
CAMPBELL SOUP	CPB	$ 5.30	$ 5.60	$ 5.92	$ 11.25	$ 11.89	$ 12.56
CARDINAL HEALTH	CAH	$ 21.65	$ 26.35	$ 32.06	$ 37.50	$ 45.64	$ 55.54
CERNER CORP.	CERN	$ 14.00	$ 15.57	$ 17.31	$ 24.45	$ 27.18	$ 30.23
C.H. ROBINSON	CHRW	$ 9.45	$ 10.41	$ 11.47	$ 13.80	$ 15.21	$ 16.76
CHURCH & DWIGHT	CHD	$ 8.25	$ 8.95	$ 9.71	$ 12.25	$ 13.29	$ 14.41
CIGNA CORPORATION	CI	$ 55.65	$ 66.10	$ 78.51	$ 76.50	$ 90.86	$ 107.92
CINTAS CORP.	CTAS	$ 20.35	$ 22.23	$ 24.29	$ 38.25	$ 41.79	$ 45.66
COCA-COLA	KO	$ 5.25	$ 5.84	$ 6.50	$ 4.90	$ 5.45	$ 6.07
COMCAST CORP.	CMCSA	$ 12.10	$ 13.85	$ 15.86	$ 15.80	$ 18.09	$ 20.70
CONAGRA BRANDS	CAG	$ 9.70	$ 10.65	$ 11.68	$ 12.45	$ 13.66	$ 15.00
CONSTELLATION	STZ	$ 35.60	$ 40.06	$ 45.08	$ 45.15	$ 50.81	$ 57.17
COSTCO WHOLESALE	COST	$ 30.50	$ 34.74	$ 39.58	$ 41.25	$ 46.99	$ 53.53
BARD (C.R.), INC.	BCR	$ 37.25	$ 41.15	$ 45.45	$ 60.00	$ 66.28	$ 73.21
DEERE & CO.	DE	$ 22.80	$ 28.11	$ 34.65	$ 35.00	$ 43.15	$ 53.19
DENTSPLY SIRONA	XRAY	$ 36.35	$ 42.03	$ 48.59	$ 41.90	$ 48.44	$ 56.01
EDWARDS LIFESCI.	EW	$ 13.35	$ 15.52	$ 18.04	$ 20.00	$ 23.25	$ 27.03
Lilly (Eli)	LLY	$ 14.10	$ 16.10	$ 18.38	$ 22.75	$ 25.97	$ 29.65
EQUIFAX, INC.	EFX	$ 25.85	$ 28.61	$ 31.66	$ 45.15	$ 49.97	$ 55.30
EXPEDITORS INT'L	EXPD	$ 11.80	$ 13.48	$ 15.39	$ 19.95	$ 22.78	$ 26.02
EXPRESS SCRIPTS.	ESRX	$ 30.45	$ 34.24	$ 38.50	$ 45.90	$ 51.61	$ 58.03
EXXON MOBIL	XOM	$ 42.30	$ 54.16	$ 69.34	$ 53.90	$ 69.01	$ 88.36
FISERV, INC.	FISV	$ 12.50	$ 13.55	$ 14.69	$ 14.50	$ 15.72	$ 17.04
FLIR SYSTEMS, INC.	FLIR	$ 13.90	$ 14.95	$ 16.07	$ 20.30	$ 21.83	$ 23.47
FOOT LOCKER	FL	$ 25.15	$ 27.57	$ 30.22	$ 45.60	$ 49.99	$ 54.80
GEN'L. DYNAMICS	GD	$ 38.35	$ 41.53	$ 44.98	$ 42.20	$ 45.70	$ 49.50
GENERAL MILLS	GIS	$ 7.50	$ 8.01	$ 8.55	$ 10.75	$ 11.48	$ 12.26
GENUINE PARTS	GPC	$ 22.70	$ 25.74	$ 29.19	$ 30.00	$ 34.02	$ 38.58
HASBRO, INC.	HAS	$ 16.05	$ 17.78	$ 19.70	$ 21.10	$ 23.38	$ 25.90
SCHEIN (HENRY) INC.	HSIC	$ 38.75	$ 42.40	$ 46.40	$ 62.50	$ 68.39	$ 74.84
HERSHEY CO. (THE)	HSY	$ 4.90	$ 5.33	$ 5.80	$ 13.15	$ 14.31	$ 15.57
HOME DEPOT	HD	$ 3.25	$ 3.61	$ 4.00	$ 0.95	$ 1.05	$ 1.17

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	Ticker Symbols	Projected Book Value of Equity 2017	2018	2019	2020	2021	2022
HORMEL FOODS	HRL	$ 8.95	$ 10.28	$ 11.81	$ 13.50	$ 15.51	$ 17.81
HUMANA INC.	HUM	$ 73.75	$ 80.05	$ 86.89	$ 110.75	$ 120.21	$ 130.48
INT'L BUS. MACH.	IBM	$ 21.95	$ 23.14	$ 24.39	$ 34.35	$ 36.21	$ 38.17
International Flavors & Fragrances Inc	IFF	$ 23.10	$ 25.93	$ 29.10	$ 36.85	$ 41.36	$ 46.42
SMUCKER (J.M.) CO.	SJM	$ 62.20	$ 67.56	$ 73.38	$ 78.05	$ 84.78	$ 92.08
JOHNSON & JOHNSON	JNJ	$ 30.05	$ 34.66	$ 39.98	$ 43.70	$ 50.41	$ 58.15
KELLOGG CO.	K	$ 6.65	$ 7.40	$ 8.24	$ 14.80	$ 16.48	$ 18.34
THE KROGER CO.	KR	$ 7.75	$ 8.72	$ 9.81	$ 13.30	$ 14.97	$ 16.84
LAB. CORP. AMER.	LH	$ 59.80	$ 66.25	$ 73.40	$ 86.75	$ 96.11	$ 106.48
MATTEL, INC.	MAT	$ 6.60	$ 8.96	$ 12.16	$ 10.35	$ 14.05	$ 19.06
McCORMICK	MKC	$ 14.70	$ 16.21	$ 17.88	$ 23.50	$ 25.92	$ 28.58
MEDTRONIC, PLC.	MDT	$ 39.00	$ 41.28	$ 43.69	$ 44.95	$ 47.58	$ 50.36
MERCK & CO.	MRK	$ 14.00	$ 15.27	$ 16.66	$ 13.35	$ 14.57	$ 15.89
MOLSON COORS	TAP	$ 55.85	$ 60.43	$ 65.38	$ 68.10	$ 73.68	$ 79.72
MONSANTO COMPANY	MON	$ 14.75	$ 17.17	$ 19.98	$ 30.50	$ 35.49	$ 41.31
NIKE, INC. `B'	NKE	$ 7.50	$ 8.97	$ 10.74	$ 10.95	$ 13.10	$ 15.68
NORTHROP GRUMMAN	NOC	$ 36.76	$ 41.29	$ 46.38	$ 45.45	$ 51.05	$ 57.35
PATTERSON COS.	PDCO	$ 13.80	$ 17.32	$ 21.73	$ 23.55	$ 29.55	$ 37.09
PAYCHEX, INC.	PAYX	$ 5.30	$ 5.93	$ 6.63	$ 6.15	$ 6.88	$ 7.70
PEPSICO, INC.	PEP	$ 8.65	$ 9.58	$ 10.61	$ 13.10	$ 14.51	$ 16.07
PERRIGO CO. PLC	PRGO	$ 43.05	$ 47.74	$ 52.94	$ 61.40	$ 68.09	$ 75.50
PFIZER INC.	PFE	$ 9.30	$ 11.11	$ 13.27	$ 9.10	$ 10.87	$ 12.98
PROCTER & GAMBLE	PG	$ 21.55	$ 25.15	$ 29.35	$ 28.25	$ 32.97	$ 38.48
QUALCOMM INC.	QCOM	$ 22.10	$ 25.78	$ 30.08	$ 26.55	$ 30.98	$ 36.14
QUEST DIAGNOST.	DGX	$ 35.55	$ 40.16	$ 45.36	$ 47.40	$ 53.54	$ 60.48
RAYTHEON	RTN	$ 36.30	$ 41.52	$ 47.50	$ 48.00	$ 54.91	$ 62.80
REPUBLIC SERVICES	RSG	$ 23.50	$ 26.39	$ 29.64	$ 32.25	$ 36.22	$ 40.68
RESMED INC.	RMD	$ 12.75	$ 15.12	$ 17.92	$ 16.05	$ 19.03	$ 22.56
ROSS STORES, INC.	ROST	$ 7.50	$ 8.23	$ 9.04	$ 14.35	$ 15.75	$ 17.29
STARBUCKS CORP.	SBUX	$ 4.45	$ 5.40	$ 6.55	$ 9.35	$ 11.34	$ 13.76
STERICYCLE INC.	SRCL	$ 33.50	$ 36.34	$ 39.42	$ 45.45	$ 49.30	$ 53.49
STRYKER CORP.	SYK	$ 28.55	$ 32.47	$ 36.92	$ 46.05	$ 52.37	$ 59.55
SYSCO CORP.	SYY	$ 4.55	$ 5.15	$ 5.83	$ 3.40	$ 3.85	$ 4.35
TARGET CORP.	TGT	$ 20.55	$ 22.88	$ 25.46	$ 29.35	$ 32.67	$ 36.37
TJX COMPANIES	TJX	$ 8.15	$ 9.48	$ 11.02	$ 15.10	$ 17.56	$ 20.41
UNITEDHEALTH GRP.	UNH	$ 49.20	$ 54.74	$ 60.91	$ 71.65	$ 79.72	$ 88.71
VARIAN MEDICAL	VAR	$ 18.90	$ 23.94	$ 30.33	$ 33.55	$ 42.50	$ 53.85
VERIZON	VZ	$ 4.00	$ 4.17	$ 4.35	$ 6.00	$ 6.26	$ 6.52
WALGREENS BOOTS	WBA	$ 30.05	$ 33.78	$ 37.96	$ 40.65	$ 45.69	$ 51.36
WAL-MART STORES	WMT	$ 22.00	$ 24.35	$ 26.96	$ 32.00	$ 35.42	$ 39.21
WASTE MANAGEMENT	WM	$ 12.25	$ 13.27	$ 14.36	$ 14.00	$ 15.16	$ 16.42
WATERS CORP.	WAT	$ 31.25	$ 32.37	$ 33.52	$ 40.00	$ 41.43	$ 42.91
WHOLE FOODS MKT.	WFM	$ 9.85	$ 11.28	$ 12.91	$ 7.35	$ 8.41	$ 9.63
GRAINGER (W.W.)	GWW	$ 30.80	$ 34.90	$ 39.54	$ 50.00	$ 56.65	$ 64.19

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	Ticker Symbols	Projected Book Value of Equity 17-18	18-19	19-20	20-21	21-22
3M COMPANY	MMM	$ 17.59	$ 19.56	$ 20.48	$ 21.49	$ 23.91
AMPHENOL CORP.	APH	$ 13.55	$ 14.91	$ 15.61	$ 16.39	$ 18.03
APPLE INC.	AAPL	$ 29.25	$ 33.76	$ 41.42	$ 50.25	$ 58.01
AT&T INC.	T	$ 21.52	$ 23.34	$ 25.90	$ 28.66	$ 31.09
AUTO. DATA PROC.	ADP	$ 10.14	$ 11.63	$ 13.54	$ 15.72	$ 18.03
BALL CORP.	BLL	$ 18.18	$ 20.14	$ 22.68	$ 25.50	$ 28.25
BAXTER INT'L	BAX	$ 17.63	$ 19.83	$ 22.50	$ 25.49	$ 28.67
BECTON, D'SON.	BDX	$ 38.20	$ 41.65	$ 41.73	$ 41.81	$ 45.58
BROWN-FORMAN `B'	BFB	$ 5.26	$ 5.92	$ 6.41	$ 6.96	$ 7.83
CAMPBELL SOUP	CPB	$ 5.45	$ 5.76	$ 8.58	$ 11.57	$ 12.23
CARDINAL HEALTH	CAH	$ 24.00	$ 29.21	$ 34.78	$ 41.57	$ 50.59
CERNER CORP.	CERN	$ 14.78	$ 16.44	$ 20.88	$ 25.82	$ 28.71
C.H. ROBINSON	CHRW	$ 9.93	$ 10.94	$ 12.64	$ 14.50	$ 15.98
CHURCH & DWIGHT	CHD	$ 8.60	$ 9.33	$ 10.98	$ 12.77	$ 13.85
CIGNA CORPORATION	CI	$ 60.87	$ 72.30	$ 77.51	$ 83.68	$ 99.39
CINTAS CORP.	CTAS	$ 21.29	$ 23.26	$ 31.27	$ 40.02	$ 43.73
COCA-COLA	KO	$ 5.55	$ 6.17	$ 5.70	$ 5.18	$ 5.76
COMCAST CORP.	CMCSA	$ 12.98	$ 14.85	$ 15.83	$ 16.94	$ 19.40
CONAGRA BRANDS	CAG	$ 10.17	$ 11.16	$ 12.07	$ 13.06	$ 14.33
CONSTELLATION	STZ	$ 37.83	$ 42.57	$ 45.12	$ 47.98	$ 53.99
COSTCO WHOLESALE	COST	$ 32.62	$ 37.16	$ 40.41	$ 44.12	$ 50.26
BARD (C.R.), INC.	BCR	$ 39.20	$ 43.30	$ 52.73	$ 63.14	$ 69.74
DEERE & CO.	DE	$ 25.45	$ 31.38	$ 34.83	$ 39.07	$ 48.17
DENTSPLY SIRONA	XRAY	$ 39.19	$ 45.31	$ 45.24	$ 45.17	$ 52.23
EDWARDS LIFESCI.	EW	$ 14.44	$ 16.78	$ 19.02	$ 21.63	$ 25.14
Lilly (Eli)	LLY	$ 15.10	$ 17.24	$ 20.56	$ 24.36	$ 27.81
EQUIFAX, INC.	EFX	$ 27.23	$ 30.13	$ 38.40	$ 47.56	$ 52.63
EXPEDITORS INT'L	EXPD	$ 12.64	$ 14.43	$ 17.67	$ 21.37	$ 24.40
EXPRESS SCRIPTS.	ESRX	$ 32.34	$ 36.37	$ 42.20	$ 48.76	$ 54.82
EXXON MOBIL	XOM	$ 48.23	$ 61.75	$ 61.62	$ 61.45	$ 78.68
FISERV, INC.	FISV	$ 13.03	$ 14.12	$ 14.60	$ 15.11	$ 16.38
FLIR SYSTEMS, INC.	FLIR	$ 14.42	$ 15.51	$ 18.19	$ 21.06	$ 22.65
FOOT LOCKER	FL	$ 26.36	$ 28.90	$ 37.91	$ 47.79	$ 52.39
GEN'L. DYNAMICS	GD	$ 39.94	$ 43.26	$ 43.59	$ 43.95	$ 47.60
GENERAL MILLS	GIS	$ 7.75	$ 8.28	$ 9.65	$ 11.11	$ 11.87
GENUINE PARTS	GPC	$ 24.22	$ 27.47	$ 29.60	$ 32.01	$ 36.30
HASBRO, INC.	HAS	$ 16.92	$ 18.74	$ 20.40	$ 22.24	$ 24.64
SCHEIN (HENRY) INC.	HSIC	$ 40.58	$ 44.40	$ 54.45	$ 65.45	$ 71.62
HERSHEY CO. (THE)	HSY	$ 5.12	$ 5.57	$ 9.48	$ 13.73	$ 14.94
HOME DEPOT	HD	$ 3.43	$ 3.80	$ 2.48	$ 1.00	$ 1.11

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies Reference Group
Projected ROE

	Ticker	Projected Book Value of Equity				
	Symbols	17-18	18-19	19-20	20-21	21-22
HORMEL FOODS	HRL	$ 9.61	$ 11.04	$ 12.65	$ 14.50	$ 16.66
HUMANA INC.	HUM	$ 76.90	$ 83.47	$ 98.82	$ 115.48	$ 125.34
INT'L BUS. MACH.	IBM	$ 22.54	$ 23.77	$ 29.37	$ 35.28	$ 37.19
International Flavors & Fragrances Inc	IFF	$ 24.51	$ 27.51	$ 32.97	$ 39.10	$ 43.89
SMUCKER (J.M.) CO.	SJM	$ 64.88	$ 70.47	$ 75.72	$ 81.41	$ 88.43
JOHNSON & JOHNSON	JNJ	$ 32.36	$ 37.32	$ 41.84	$ 47.05	$ 54.28
KELLOGG CO.	K	$ 7.03	$ 7.82	$ 11.52	$ 15.64	$ 17.41
THE KROGER CO.	KR	$ 8.24	$ 9.27	$ 11.56	$ 14.13	$ 15.90
LAB. CORP. AMER.	LH	$ 63.03	$ 69.82	$ 80.07	$ 91.43	$ 101.29
MATTEL, INC.	MAT	$ 7.78	$ 10.56	$ 11.25	$ 12.20	$ 16.56
McCORMICK	MKC	$ 15.46	$ 17.05	$ 20.69	$ 24.71	$ 27.25
MEDTRONIC, PLC.	MDT	$ 40.14	$ 42.49	$ 44.32	$ 46.26	$ 48.97
MERCK & CO.	MRK	$ 14.64	$ 15.97	$ 15.01	$ 13.96	$ 15.23
MOLSON COORS	TAP	$ 58.14	$ 62.91	$ 66.74	$ 70.89	$ 76.70
MONSANTO COMPANY	MON	$ 15.96	$ 18.57	$ 25.24	$ 33.00	$ 38.40
NIKE, INC. `B'	NKE	$ 8.24	$ 9.86	$ 10.84	$ 12.03	$ 14.39
NORTHROP GRUMMAN	NOC	$ 39.03	$ 43.84	$ 45.92	$ 48.25	$ 54.20
PATTERSON COS.	PDCO	$ 15.56	$ 19.52	$ 22.64	$ 26.55	$ 33.32
PAYCHEX, INC.	PAYX	$ 5.61	$ 6.28	$ 6.39	$ 6.51	$ 7.29
PEPSICO, INC.	PEP	$ 9.12	$ 10.10	$ 11.86	$ 13.81	$ 15.29
PERRIGO CO. PLC	PRGO	$ 45.39	$ 50.34	$ 57.17	$ 64.74	$ 71.80
PFIZER INC.	PFE	$ 10.20	$ 12.19	$ 11.18	$ 9.98	$ 11.92
PROCTER & GAMBLE	PG	$ 23.35	$ 27.25	$ 28.80	$ 30.61	$ 35.73
QUALCOMM INC.	QCOM	$ 23.94	$ 27.93	$ 28.32	$ 28.76	$ 33.56
QUEST DIAGNOST.	DGX	$ 37.85	$ 42.76	$ 46.38	$ 50.47	$ 57.01
RAYTHEON	RTN	$ 38.91	$ 44.51	$ 47.75	$ 51.45	$ 58.85
REPUBLIC SERVICES	RSG	$ 24.95	$ 28.02	$ 30.95	$ 34.24	$ 38.45
RESMED INC.	RMD	$ 13.93	$ 16.52	$ 16.99	$ 17.54	$ 20.80
ROSS STORES, INC.	ROST	$ 7.87	$ 8.63	$ 11.69	$ 15.05	$ 16.52
STARBUCKS CORP.	SBUX	$ 4.92	$ 5.97	$ 7.95	$ 10.35	$ 12.55
STERICYCLE INC.	SRCL	$ 34.92	$ 37.88	$ 42.44	$ 47.38	$ 51.39
STRYKER CORP.	SYK	$ 30.51	$ 34.69	$ 41.49	$ 49.21	$ 55.96
SYSCO CORP.	SYY	$ 4.85	$ 5.49	$ 4.61	$ 3.62	$ 4.10
TARGET CORP.	TGT	$ 21.71	$ 24.17	$ 27.41	$ 31.01	$ 34.52
TJX COMPANIES	TJX	$ 8.81	$ 10.25	$ 13.06	$ 16.33	$ 18.98
UNITEDHEALTH GRP.	UNH	$ 51.97	$ 57.83	$ 66.28	$ 75.69	$ 84.21
VARIAN MEDICAL	VAR	$ 21.42	$ 27.14	$ 31.94	$ 38.03	$ 48.18
VERIZON	VZ	$ 4.09	$ 4.26	$ 5.17	$ 6.13	$ 6.39
WALGREENS BOOTS	WBA	$ 31.91	$ 35.87	$ 39.31	$ 43.17	$ 48.52
WAL-MART STORES	WMT	$ 23.18	$ 25.65	$ 29.48	$ 33.71	$ 37.32
WASTE MANAGEMENT	WM	$ 12.76	$ 13.82	$ 14.18	$ 14.58	$ 15.79
WATERS CORP.	WAT	$ 31.81	$ 32.95	$ 36.76	$ 40.71	$ 42.17
WHOLE FOODS MKT.	WFM	$ 10.56	$ 12.09	$ 10.13	$ 7.88	$ 9.02
GRAINGER (W.W.)	GWW	$ 32.85	$ 37.22	$ 44.77	$ 53.33	$ 60.42

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies Reference Group
Projected ROE

	Ticker Symbols	Projected ROE = PE/BV 2018	2019	2020	2021	2022
3M COMPANY	MMM	56.3%	56.3%	59.8%	63.4%	63.4%
AMPHENOL CORP.	APH	24.4%	24.4%	25.6%	26.9%	26.9%
APPLE INC.	AAPL	35.9%	35.9%	33.8%	32.2%	32.2%
AT&T INC.	T	14.6%	14.6%	14.3%	14.0%	14.0%
AUTO. DATA PROC.	ADP	41.3%	41.3%	40.6%	40.1%	40.1%
BALL CORP.	BLL	11.9%	11.9%	11.7%	11.5%	11.5%
BAXTER INT'L	BAX	14.3%	14.3%	14.2%	14.1%	14.1%
BECTON, D'SON.	BDX	27.0%	27.0%	29.4%	31.9%	31.9%
BROWN-FORMAN `B'	BFB	42.8%	42.8%	44.5%	46.1%	46.1%
CAMPBELL SOUP	CPB	59.1%	59.1%	41.9%	32.9%	32.9%
CARDINAL HEALTH	CAH	21.8%	21.8%	22.3%	22.7%	22.7%
CERNER CORP.	CERN	18.9%	18.9%	16.5%	14.9%	14.9%
C.H. ROBINSON	CHRW	41.1%	41.1%	39.2%	37.6%	37.6%
CHURCH & DWIGHT	CHD	24.2%	24.2%	22.3%	20.8%	20.8%
CIGNA CORPORATION	CI	18.0%	18.0%	20.0%	22.0%	22.0%
CINTAS CORP.	CTAS	23.6%	23.6%	19.2%	16.4%	16.4%
COCA-COLA	KO	37.1%	37.1%	44.7%	54.8%	54.8%
COMCAST CORP.	CMCSA	17.6%	17.6%	19.0%	20.3%	20.3%
CONAGRA BRANDS	CAG	18.8%	18.8%	19.1%	19.3%	19.3%
CONSTELLATION	STZ	23.8%	23.8%	25.3%	26.7%	26.7%
COSTCO WHOLESALE	COST	20.1%	20.1%	21.0%	21.9%	21.9%
BARD (C.R.), INC.	BCR	32.4%	32.4%	29.4%	27.1%	27.1%
DEERE & CO.	DE	23.0%	23.0%	25.6%	28.1%	28.1%
DENTSPLY SIRONA	XRAY	8.1%	8.1%	9.4%	10.9%	10.9%
EDWARDS LIFESCI.	EW	28.2%	28.2%	28.9%	29.6%	29.6%
Lilly (Eli)	LLY	31.0%	31.0%	29.7%	28.6%	28.6%
EQUIFAX, INC.	EFX	24.6%	24.6%	21.4%	19.1%	19.1%
EXPEDITORS INT'L	EXPD	21.2%	21.2%	19.8%	18.7%	18.7%
EXPRESS SCRIPTS.	ESRX	17.7%	17.7%	17.2%	16.7%	16.7%
EXXON MOBIL	XOM	10.8%	10.8%	13.8%	17.7%	17.7%
FISERV, INC.	FISV	42.4%	42.4%	44.5%	46.6%	46.6%
FLIR SYSTEMS, INC.	FLIR	13.8%	13.8%	12.6%	11.7%	11.7%
FOOT LOCKER	FL	21.6%	21.6%	18.1%	15.7%	15.7%
GEN'L. DYNAMICS	GD	26.6%	26.6%	28.6%	30.7%	30.7%
GENERAL MILLS	GIS	42.4%	42.4%	38.9%	36.0%	36.0%
GENUINE PARTS	GPC	22.5%	22.5%	23.7%	24.8%	24.8%
HASBRO, INC.	HAS	32.7%	32.7%	33.3%	33.9%	33.9%
SCHEIN (HENRY) INC.	HSIC	19.6%	19.6%	17.4%	15.9%	15.9%
HERSHEY CO. (THE)	HSY	103.2%	103.2%	66.0%	49.5%	49.5%
HOME DEPOT	HD	234.6%	234.6%	400.0%	1096.2%	1096.2%

Southern California Edison Company
Comparable Earnings Analysis
Unregulated Companies Reference Group
Projected ROE

	Ticker Symbols	Projected ROE = PE/BV 2018	2019	2020	2021	2022
HORMEL FOODS	HRL	19.7%	19.7%	19.8%	19.8%	19.8%
HUMANA INC.	HUM	15.9%	15.9%	14.6%	13.6%	13.6%
INT'L BUS. MACH.	IBM	55.9%	55.9%	47.7%	41.8%	41.8%
International Flavors & Fragrances Inc	IFF	26.6%	26.6%	24.9%	23.5%	23.5%
SMUCKER (J.M.) CO.	SJM	11.3%	11.3%	11.4%	11.5%	11.5%
JOHNSON & JOHNSON	JNJ	23.0%	23.0%	23.7%	24.3%	24.3%
KELLOGG CO.	K	62.6%	62.6%	47.3%	38.8%	38.8%
THE KROGER CO.	KR	27.3%	27.3%	24.7%	22.7%	22.7%
LAB. CORP. AMER.	LH	16.6%	16.6%	16.0%	15.6%	15.6%
MATTEL, INC.	MAT	15.7%	15.7%	20.0%	25.0%	25.0%
McCORMICK	MKC	29.3%	29.3%	26.6%	24.5%	24.5%
MEDTRONIC, PLC.	MDT	14.9%	14.9%	15.1%	15.3%	15.3%
MERCK & CO.	MRK	28.7%	28.7%	33.3%	39.1%	39.1%
MOLSON COORS	TAP	8.4%	8.4%	8.5%	8.7%	8.7%
MONSANTO COMPANY	MON	33.5%	33.5%	28.7%	25.6%	25.6%
NIKE, INC. `B'	NKE	36.5%	36.5%	39.7%	42.8%	42.8%
NORTHROP GRUMMAN	NOC	34.8%	34.8%	37.4%	39.9%	39.9%
PATTERSON COS.	PDCO	16.9%	16.9%	18.3%	19.6%	19.6%
PAYCHEX, INC.	PAYX	44.8%	44.8%	49.3%	54.1%	54.1%
PEPSICO, INC.	PEP	62.6%	62.6%	59.0%	56.2%	56.2%
PERRIGO CO. PLC	PRGO	10.7%	10.7%	10.5%	10.3%	10.3%
PFIZER INC.	PFE	15.8%	15.8%	20.6%	27.5%	27.5%
PROCTER & GAMBLE	PG	19.5%	19.5%	21.5%	23.6%	23.6%
QUALCOMM INC.	QCOM	20.7%	20.7%	23.8%	27.4%	27.4%
QUEST DIAGNOST.	DGX	16.6%	16.6%	17.2%	17.9%	17.9%
RAYTHEON	RTN	21.9%	21.9%	23.4%	24.8%	24.8%
REPUBLIC SERVICES	RSG	10.8%	10.8%	11.0%	11.2%	11.2%
RESMED INC.	RMD	20.4%	20.4%	23.5%	27.0%	27.0%
ROSS STORES, INC.	ROST	43.3%	43.3%	35.1%	29.9%	29.9%
STARBUCKS CORP.	SBUX	51.7%	51.7%	47.2%	44.0%	44.0%
STERICYCLE INC.	SRCL	14.6%	14.6%	14.1%	13.7%	13.7%
STRYKER CORP.	SYK	19.0%	19.0%	18.1%	17.3%	17.3%
SYSCO CORP.	SYY	57.2%	57.2%	77.0%	110.9%	110.9%
TARGET CORP.	TGT	22.3%	22.3%	21.9%	21.5%	21.5%
TJX COMPANIES	TJX	50.8%	50.8%	46.3%	43.1%	43.1%
UNITEDHEALTH GRP.	UNH	21.0%	21.0%	20.4%	19.8%	19.8%
VARIAN MEDICAL	VAR	17.7%	17.7%	19.1%	20.3%	20.3%
VERIZON	VZ	95.7%	95.7%	82.1%	72.3%	72.3%
WALGREENS BOOTS	WBA	17.6%	17.6%	18.1%	18.5%	18.5%
WAL-MART STORES	WMT	20.8%	20.8%	20.0%	19.4%	19.4%
WASTE MANAGEMENT	WM	26.7%	26.7%	28.2%	29.7%	29.7%
WATERS CORP.	WAT	23.4%	23.4%	21.8%	20.4%	20.4%
WHOLE FOODS MKT.	WFM	14.1%	14.1%	19.3%	28.3%	28.3%
GRAINGER (W.W.)	GWW	37.9%	37.9%	35.7%	34.0%	34.0%
		31.0%	31.0%	32.2%	40.8%	40.8%
			5 Yr Avg:		**35.14%**	

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	**)**	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-20

EXHIBIT TO THE TESTIMONY OF
DR. PAUL T. HUNT

ON BEHALF OF
SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

Line No.		Company	Value Line Beta	Debt/Equity Ratio	Unlevered Beta	Beta Relevered at SCE's D/E Ratio	ROE at VL Beta	CAPM ROE at Unlevered /Relevered Beta	Average Px_High, Px_Low	Shares Outstanding	Long-Term Debt	Short-Term Debt
1.	ALE	Allete Inc	0.80	41.99%	0.6390	0.8103	11.41%	11.51%	71.78	50.90	1,370.20	163.90
2.	LNT	Alliant Energy Corp	0.70	50.10%	0.5382	0.6825	10.45%	10.28%	40.51	227.82	4,316.10	307.40
3.	AEE	Ameren Corp	0.65	61.28%	0.4753	0.6027	9.97%	9.51%	55.11	242.60	6,597.00	1,595.00
4.	AEP	American Electric Power Company Inc	0.65	60.82%	0.4762	0.6039	9.97%	9.52%	69.46	491.71	16,722.20	4,050.20
5.	AGR	AVANGRID Inc.	NMF	37.58%					44.76	309.07	4,507.00	692.00
6.	AVA	Avista Corp	0.70	60.71%	0.5131	0.6507	10.45%	9.97%	47.02	64.39	1,729.66	108.32
7.	BKH	Black Hills Corp	0.85	88.65%	0.5549	0.7036	11.89%	10.48%	68.94	53.46	3,210.73	56.69
8.	CNP	CenterPoint Energy Inc	0.85	72.82%	0.5916	0.7502	11.89%	10.93%	27.66	430.96	7,892.00	787.00
9.	CMS	CMS Energy Corp	0.65	77.69%	0.4433	0.5622	9.97%	9.12%	46.18	280.00	9,233.00	812.00
10.	ED	Consolidated Edison Inc	0.50	63.14%	0.3626	0.4598	8.52%	8.14%	81.51	305.00	14,829.00	869.00
11.	D	Dominion Energy	0.65	75.07%	0.4482	0.5683	9.97%	9.18%	76.49	629.00	31,096.00	5,018.00
12.	DTE	DTE Energy Company	0.65	62.16%	0.4734	0.6004	9.97%	9.49%	106.10	179.39	11,758.00	72.00
13.	DUK	Duke Energy Corp New	0.60	89.35%	0.3906	0.4953	9.49%	8.48%	84.03	700.00	47,021.00	5,535.00
14.	EIX	Edison International	0.60	51.00%	0.4594	0.5826	9.49%	9.32%	77.86	325.81	11,662.00	1,276.00
15.	EE	El Paso Electric Co	0.75	67.54%	0.5337	0.6768	10.93%	10.23%	51.80	40.39	1,195.63	217.38
16.	ETR	Entergy Corp	0.65	114.46%	0.3854	0.4887	9.97%	8.42%	76.01	179.43	13,950.78	1,659.82
17.	ES	Eversource Energy	0.65	57.41%	0.4835	0.6131	9.97%	9.61%	60.56	316.89	9,267.89	1,749.38
18.	EXC	Exelon Corp	0.65	109.28%	0.3926	0.4979	9.97%	8.50%	36.94	926.10	31,685.00	5,693.00
19.	FE	FirstEnergy Corp	0.65	166.66%	0.3250	0.4122	9.97%	7.68%	30.64	443.74	17,762.00	4,897.00
20.	FTS	Fortis Inc	0.65	152.41%	0.3395	0.4306	9.97%	7.86%	35.42	415.60	20,728.00	1,711.00
21.	HE	Hawaiian Electric Industries Inc	0.70	51.68%	0.5343	0.6776	10.45%	10.23%	32.41	108.75	1,618.65	202.45
22.	IDA	IDACORP Inc	0.70	40.42%	0.5634	0.7144	10.45%	10.59%	85.68	50.39	1,744.99	0.00
23.	MGEE	MGE Energy Inc	0.75	17.50%	0.6787	0.8607	10.93%	11.99%	65.25	34.67	391.47	4.38
24.	NWE	NorthWestern Corporation	0.65	65.89%	0.4658	0.5908	9.97%	9.40%	59.69	52.09	1,817.47	230.92
25.	OGE	OGE Energy Corp	0.95	43.81%	0.7523	0.9540	12.85%	12.89%	34.94	199.70	2,703.20	353.00
26.	OTTR	Otter Tail Corp	0.90	37.91%	0.7332	0.9298	12.37%	12.66%	39.75	39.47	490.37	104.37
27.	PCG	Pacific Gas and Electric Company	0.65	53.77%	0.4914	0.6232	9.97%	9.71%	66.56	510.61	16,813.00	1,463.00
28.	PNW	Pinnacle West Capital Corp	0.65	48.20%	0.5042	0.6394	9.97%	9.87%	85.66	111.56	4,273.89	332.30
29.	PNM	PNM Resources Inc	0.75	87.49%	0.4918	0.6237	10.93%	9.71%	38.56	79.65	1,969.30	717.96
30.	POR	Portland General Electric Company	0.70	58.28%	0.5187	0.6577	10.45%	10.04%	45.28	89.07	2,200.00	150.00
31.	PPL	PPL Corporation	0.70	77.25%	0.4783	0.6066	10.45%	9.55%	38.02	682.43	17,958.00	2,083.00
32.	PEG	Public Service Enterprise Group Inc	0.65	53.30%	0.4925	0.6246	9.97%	9.72%	43.52	505.00	10,898.00	815.00
33.	SCG	SCANA Corporation	0.65	80.39%	0.4385	0.5561	9.97%	9.06%	64.00	142.90	6,466.00	886.00
34.	SRE	Sempra Energy	0.80	61.19%	0.5852	0.7421	11.41%	10.85%	112.65	251.00	14,409.00	2,893.00
35.	SO	Southern Co	0.55	103.76%	0.3390	0.4299	9.01%	7.85%	47.38	994.10	42,786.00	6,087.00
36.	VVC	Vectren Corp	0.70	37.21%	0.5722	0.7257	10.45%	10.70%	58.86	82.90	1,590.20	225.50
37.	WEC	WEC Energy Group	0.60	50.98%	0.4595	0.5827	9.49%	9.32%	61.99	315.58	9,143.60	828.40
38.	XEL	Xcel Energy Inc	0.60	63.86%	0.4338	0.5501	9.49%	9.01%	46.44	507.76	13,696.46	1,360.45
39.		Minimum						7.68%				
40.		Maximum						12.89%				
41.		Midpoint						10.29%				
42.		Average	0.6892			0.6292		9.77%				
43.		Median						9.61%				
44.		Number of Estimates						37				
45.		SCE Debt/Equity Ratio		44.69%								
46.		Risk-Free Rate*		3.71%								
47.		Equity Risk Premium		9.62%								

48. *IHS Global Insight projection of 30-year Treasury rate, less 0.04% adder, to estimate 20-year Treasury rate

	Average Px_High, Px_Low	Shares Outstanding	Long-Term Debt	Short-Term Debt
EIX	77.86355	325.8112	11,662	1,276
SCE			11,024	219

SCE Total Assets / EIX Total Assets 2017 Q2 10-Q		
	Total Asset	SCE/EIX
SCE	52,314	99%
EIX	52,753	

Line No.		Company	Debt Adjustment	Value of Debt	Value of Equity	Debt Percentage	Equity Percentage	D/E Ratio
1.	ALE	Allete Inc	0	1,534.10	3,653.35	29.57%	70.43%	41.99%
2.	LNT	Alliant Energy Corp	0	4,623.50	9,229.12	33.38%	66.62%	50.10%
3.	AEE	Ameren Corp	0	8,192.00	13,368.47	38.00%	62.00%	61.28%
4.	AEP	American Electric Power Company Inc	0	20,772.40	34,154.32	37.82%	62.18%	60.82%
5.	AGR	AVANGRID Inc.	0	5,199.00	13,833.17	27.32%	72.68%	37.58%
6.	AVA	Avista Corp	0	1,837.98	3,027.44	37.78%	62.22%	60.71%
7.	BKH	Black Hills Corp	0	3,267.42	3,685.59	46.99%	53.01%	88.65%
8.	CNP	CenterPoint Energy Inc	0	8,679.00	11,919.22	42.13%	57.87%	72.82%
9.	CMS	CMS Energy Corp	0	10,045.00	12,930.40	43.72%	56.28%	77.69%
10.	ED	Consolidated Edison Inc	0	15,698.00	24,860.55	38.70%	61.30%	63.14%
11.	D	Dominion Energy	0	36,114.00	48,109.07	42.88%	57.12%	75.07%
12.	DTE	DTE Energy Company	0	11,830.00	19,032.11	38.33%	61.67%	62.16%
13.	DUK	Duke Energy Corp New	0	52,556.00	58,817.50	47.19%	52.81%	89.35%
14.	EIX	Edison International	0	12,938.00	25,368.82	33.77%	66.23%	51.00%
15.	EE	El Paso Electric Co	0	1,413.01	2,092.16	40.31%	59.69%	67.54%
16.	ETR	Entergy Corp	0	15,610.60	13,638.70	53.37%	46.63%	114.46%
17.	ES	Eversource Energy	0	11,017.27	19,189.02	36.47%	63.53%	57.41%
18.	EXC	Exelon Corp	0	37,378.00	34,205.39	52.22%	47.78%	109.28%
19.	FE	FirstEnergy Corp	0	22,659.00	13,596.19	62.50%	37.50%	166.66%
20.	FTS	Fortis Inc	0	22,439.00	14,722.42	60.38%	39.62%	152.41%
21.	HE	Hawaiian Electric Industries Inc	0	1,821.11	3,523.89	34.07%	65.93%	51.68%
22.	IDA	IDACORP Inc	0	1,744.99	4,317.35	28.78%	71.22%	40.42%
23.	MGEE	MGE Energy Inc	0	395.85	2,262.09	14.89%	85.11%	17.50%
24.	NWE	NorthWestern Corporation	0	2,048.39	3,108.98	39.72%	60.28%	65.89%
25.	OGE	OGE Energy Corp	0	3,056.20	6,976.66	30.46%	69.54%	43.81%
26.	OTTR	Otter Tail Corp	0	594.74	1,568.88	27.49%	72.51%	37.91%
27.	PCG	Pacific Gas and Electric Company	0	18,276.00	33,986.22	34.97%	65.03%	53.77%
28.	PNW	Pinnacle West Capital Corp	0	4,606.19	9,556.38	32.52%	67.48%	48.20%
29.	PNM	PNM Resources Inc	0	2,687.26	3,071.64	46.66%	53.34%	87.49%
30.	POR	Portland General Electric Company	0	2,350.00	4,032.55	36.82%	63.18%	58.28%
31.	PPL	PPL Corporation	0	20,041.00	25,943.32	43.58%	56.42%	77.25%
32.	PEG	Public Service Enterprise Group Inc	0	11,713.00	21,975.08	34.77%	65.23%	53.30%
33.	SCG	SCANA Corporation	0	7,352.00	9,144.89	44.57%	55.43%	80.39%
34.	SRE	Sempra Energy	0	17,302.00	28,274.52	37.96%	62.04%	61.19%
35.	SO	Southern Co	0	48,873.00	47,100.46	50.92%	49.08%	103.76%
36.	VVC	Vectren Corp	0	1,815.70	4,879.49	27.12%	72.88%	37.21%
37.	WEC	WEC Energy Group	0	9,972.00	19,561.18	33.77%	66.23%	50.98%
38.	XEL	Xcel Energy Inc	0	15,056.91	23,579.24	38.97%	61.03%	63.86%
39.		Minimum						
40.		Maximum						
41.		Midpoint						
42.		Average						
43.		Median						
44.		Number of Estimates						
45.		SCE Debt/Equity Ratio						
46.		Risk-Free Rate*						
47.		Equity Risk Premium						
48.		*IHS Global Insight projection of 30-year Treasury rate, less 0.04% adder, to estimate 20-year Treasury rate						

EIX	12,938	25,368.8167	33.77%	66.23%	51.00%
SCE	11,243	25,157.7024	30.89%	69.11%	44.69%

Line No.		Company	Value Line Beta	Debt/Equity Ratio	Unlevered Beta	Beta Relevered at SCE's D/E Ratio	ROE at VL Beta	eCAPM ROE at Unlevered /Relevered Beta	Average Px_High, Px_Low	Shares Outstanding	Long-Term Debt	Short-Term Debt
1.	ALE	Allete Inc	0.80	41.99%	0.6390	0.8103	11.41%	11.97%	71.78	50.90	1,370.20	163.90
2.	LNT	Alliant Energy Corp	0.70	50.10%	0.5382	0.6825	10.45%	11.04%	40.51	227.82	4,316.10	307.40
3.	AEE	Ameren Corp	0.65	61.28%	0.4753	0.6027	9.97%	10.47%	55.11	242.60	6,597.00	1,595.00
4.	AEP	American Electric Power Company Inc	0.65	60.82%	0.4762	0.6039	9.97%	10.48%	69.46	491.71	16,722.20	4,050.20
5.	AGR	AVANGRID Inc.	NMF	37.58%					44.76	309.07	4,507.00	692.00
6.	AVA	Avista Corp	0.70	60.71%	0.5131	0.6507	10.45%	10.81%	47.02	64.39	1,729.66	108.32
7.	BKH	Black Hills Corp	0.85	88.65%	0.5549	0.7036	11.89%	11.20%	68.94	53.46	3,210.73	56.69
8.	CNP	CenterPoint Energy Inc	0.85	72.82%	0.5916	0.7502	11.89%	11.53%	27.66	430.96	7,892.00	787.00
9.	CMS	CMS Energy Corp	0.65	77.69%	0.4433	0.5622	9.97%	10.18%	46.18	280.00	9,233.00	812.00
10.	ED	Consolidated Edison Inc	0.50	63.14%	0.3626	0.4598	8.52%	9.44%	81.51	305.00	14,829.00	869.00
11.	D	Dominion Energy	0.65	75.07%	0.4482	0.5683	9.97%	10.22%	76.49	629.00	31,096.00	5,018.00
12.	DTE	DTE Energy Company	0.65	62.16%	0.4734	0.6004	9.97%	10.45%	106.10	179.39	11,758.00	72.00
13.	DUK	Duke Energy Corp New	0.60	89.35%	0.3906	0.4953	9.49%	9.69%	84.03	700.00	47,021.00	5,535.00
14.	EIX	Edison International	0.60	51.00%	0.4594	0.5826	9.49%	10.32%	77.86	325.81	11,662.00	1,276.00
15.	EE	El Paso Electric Co	0.75	67.54%	0.5337	0.6768	10.93%	11.00%	51.80	40.39	1,195.63	217.38
16.	ETR	Entergy Corp	0.65	114.46%	0.3854	0.4887	9.97%	9.65%	76.01	179.43	13,950.78	1,659.82
17.	ES	Eversource Energy	0.65	57.41%	0.4835	0.6131	9.97%	10.54%	60.56	316.89	9,267.89	1,749.38
18.	EXC	Exelon Corp	0.65	109.28%	0.3926	0.4979	9.97%	9.71%	36.94	926.10	31,685.00	5,693.00
19.	FE	FirstEnergy Corp	0.65	166.66%	0.3250	0.4122	9.97%	9.09%	30.64	443.74	17,762.00	4,897.00
20.	FTS	Fortis Inc	0.65	152.41%	0.3395	0.4306	9.97%	9.23%	35.42	415.60	20,728.00	1,711.00
21.	HE	Hawaiian Electric Industries Inc	0.70	51.68%	0.5343	0.6776	10.45%	11.01%	32.41	108.75	1,618.65	202.45
22.	IDA	IDACORP Inc	0.70	40.42%	0.5634	0.7144	10.45%	11.27%	85.68	50.39	1,744.99	0.00
23.	MGEE	MGE Energy Inc	0.75	17.50%	0.6787	0.8607	10.93%	12.33%	65.25	34.67	391.47	4.38
24.	NWE	NorthWestern Corporation	0.65	65.89%	0.4658	0.5908	9.97%	10.38%	59.69	52.09	1,817.47	230.92
25.	OGE	OGE Energy Corp	0.95	43.81%	0.7523	0.9540	12.85%	13.00%	34.94	199.70	2,703.20	353.00
26.	OTTR	Otter Tail Corp	0.90	37.91%	0.7332	0.9298	12.37%	12.83%	39.75	39.47	490.37	104.37
27.	PCG	Pacific Gas and Electric Company	0.65	53.77%	0.4914	0.6232	9.97%	10.62%	66.56	510.61	16,813.00	1,463.00
28.	PNW	Pinnacle West Capital Corp	0.65	48.20%	0.5042	0.6394	9.97%	10.73%	85.66	111.56	4,273.89	332.30
29.	PNM	PNM Resources Inc	0.75	87.49%	0.4918	0.6237	10.93%	10.62%	38.56	79.65	1,969.30	717.96
30.	POR	Portland General Electric Company	0.70	58.28%	0.5187	0.6577	10.45%	10.86%	45.28	89.07	2,200.00	150.00
31.	PPL	PPL Corporation	0.70	77.25%	0.4783	0.6066	10.45%	10.50%	38.02	682.43	17,958.00	2,083.00
32.	PEG	Public Service Enterprise Group Inc	0.65	53.30%	0.4925	0.6246	9.97%	10.63%	43.52	505.00	10,898.00	815.00
33.	SCG	SCANA Corporation	0.65	80.39%	0.4385	0.5561	9.97%	10.13%	64.00	142.90	6,466.00	886.00
34.	SRE	Sempra Energy	0.80	61.19%	0.5852	0.7421	11.41%	11.47%	112.65	251.00	14,409.00	2,893.00
35.	SO	Southern Co	0.55	103.76%	0.3390	0.4299	9.01%	9.22%	47.38	994.10	42,786.00	6,087.00
36.	VVC	Vectren Corp	0.70	37.21%	0.5722	0.7257	10.45%	11.36%	58.86	82.90	1,590.20	225.50
37.	WEC	WEC Energy Group	0.60	50.98%	0.4595	0.5827	9.49%	10.32%	61.99	315.58	9,143.60	828.40
38.	XEL	Xcel Energy Inc	0.60	63.86%	0.4338	0.5501	9.49%	10.09%	46.44	507.76	13,696.46	1,360.45
39.		Minimum						9.09%				
40.		Maximum						13.00%				
41.		Midpoint						11.05%				
42.		Average	0.6892			0.6292		10.66%				
43.		Median						10.54%				
44.		Number of Estimates						37				
45.		SCE Debt/Equity Ratio		44.69%								
46.		Risk-Free Rate*		3.71%								
47.		Equity Risk Premium		9.62%								

48. *IHS Global Insight projection of 30-year Treasury rate, less 0.04% adder, to estimate 20-year Treasury rate

	Average Px_High, Px_Low	Shares Outstanding	Long-Term Debt	Short-Term Debt
EIX	77.86355	325.8112	11,662	1,276
SCE			11,024	219

SCE Total Assets / EIX Total Assets 2017 Q2 10-Q		
	Total Asset	SCE/EIX
SCE	52,314	99%
EIX	52,753	

Line No.		Company	Debt Adjustment	Value of Debt	Value of Equity	Debt Percentage	Equity Percentage	D/E Ratio
1.	ALE	Allete Inc	0	1,534.10	3,653.35	29.57%	70.43%	41.99%
2.	LNT	Alliant Energy Corp	0	4,623.50	9,229.12	33.38%	66.62%	50.10%
3.	AEE	Ameren Corp	0	8,192.00	13,368.47	38.00%	62.00%	61.28%
4.	AEP	American Electric Power Company Inc	0	20,772.40	34,154.32	37.82%	62.18%	60.82%
5.	AGR	AVANGRID Inc.	0	5,199.00	13,833.17	27.32%	72.68%	37.58%
6.	AVA	Avista Corp	0	1,837.98	3,027.44	37.78%	62.22%	60.71%
7.	BKH	Black Hills Corp	0	3,267.42	3,685.59	46.99%	53.01%	88.65%
8.	CNP	CenterPoint Energy Inc	0	8,679.00	11,919.22	42.13%	57.87%	72.82%
9.	CMS	CMS Energy Corp	0	10,045.00	12,930.40	43.72%	56.28%	77.69%
10.	ED	Consolidated Edison Inc	0	15,698.00	24,860.55	38.70%	61.30%	63.14%
11.	D	Dominion Energy	0	36,114.00	48,109.07	42.88%	57.12%	75.07%
12.	DTE	DTE Energy Company	0	11,830.00	19,032.11	38.33%	61.67%	62.16%
13.	DUK	Duke Energy Corp New	0	52,556.00	58,817.50	47.19%	52.81%	89.35%
14.	EIX	Edison International	0	12,938.00	25,368.82	33.77%	66.23%	51.00%
15.	EE	El Paso Electric Co	0	1,413.01	2,092.16	40.31%	59.69%	67.54%
16.	ETR	Entergy Corp	0	15,610.60	13,638.70	53.37%	46.63%	114.46%
17.	ES	Eversource Energy	0	11,017.27	19,189.02	36.47%	63.53%	57.41%
18.	EXC	Exelon Corp	0	37,378.00	34,205.39	52.22%	47.78%	109.28%
19.	FE	FirstEnergy Corp	0	22,659.00	13,596.19	62.50%	37.50%	166.66%
20.	FTS	Fortis Inc	0	22,439.00	14,722.42	60.38%	39.62%	152.41%
21.	HE	Hawaiian Electric Industries Inc	0	1,821.11	3,523.89	34.07%	65.93%	51.68%
22.	IDA	IDACORP Inc	0	1,744.99	4,317.35	28.78%	71.22%	40.42%
23.	MGEE	MGE Energy Inc	0	395.85	2,262.09	14.89%	85.11%	17.50%
24.	NWE	NorthWestern Corporation	0	2,048.39	3,108.98	39.72%	60.28%	65.89%
25.	OGE	OGE Energy Corp	0	3,056.20	6,976.66	30.46%	69.54%	43.81%
26.	OTTR	Otter Tail Corp	0	594.74	1,568.88	27.49%	72.51%	37.91%
27.	PCG	Pacific Gas and Electric Company	0	18,276.00	33,986.22	34.97%	65.03%	53.77%
28.	PNW	Pinnacle West Capital Corp	0	4,606.19	9,556.38	32.52%	67.48%	48.20%
29.	PNM	PNM Resources Inc	0	2,687.26	3,071.64	46.66%	53.34%	87.49%
30.	POR	Portland General Electric Company	0	2,350.00	4,032.55	36.82%	63.18%	58.28%
31.	PPL	PPL Corporation	0	20,041.00	25,943.32	43.58%	56.42%	77.25%
32.	PEG	Public Service Enterprise Group Inc	0	11,713.00	21,975.08	34.77%	65.23%	53.30%
33.	SCG	SCANA Corporation	0	7,352.00	9,144.89	44.57%	55.43%	80.39%
34.	SRE	Sempra Energy	0	17,302.00	28,274.52	37.96%	62.04%	61.19%
35.	SO	Southern Co	0	48,873.00	47,100.46	50.92%	49.08%	103.76%
36.	VVC	Vectren Corp	0	1,815.70	4,879.49	27.12%	72.88%	37.21%
37.	WEC	WEC Energy Group	0	9,972.00	19,561.18	33.77%	66.23%	50.98%
38.	XEL	Xcel Energy Inc	0	15,056.91	23,579.24	38.97%	61.03%	63.86%
39.		Minimum						
40.		Maximum						
41.		Midpoint						
42.		Average						
43.		Median						
44.		Number of Estimates						
45.		SCE Debt/Equity Ratio						
46.		Risk-Free Rate*						
47.		Equity Risk Premium						
48.		*IHS Global Insight projection of 30-year Treasury rate, less 0.04% adder, to estimate 20-year Treasury rate						

EIX		12,938	25,368.8167	33.77%	66.23%	51.00%
SCE		11,243	25,157.7024	30.89%	69.11%	44.69%

Market Risk Premium		
Earnings Growth Rate	11.06%	a
Dividend Yield	2.04%	b
Market DCF Return	13.33%	c = b * (1 + a) + a
Less: Risk Free Rate	3.71%	d
Market Risk Premium	9.62%	c - d

Month	EPS (Forecast)	Monthly EPS Growth Rate	Dividend Yield (Forecast)	Monthly Dividend Yield Growth Rate
Aug-18	137.51		2.17%	
Sep-18		1.15%		-0.28%
Oct-18		1.15%		-0.28%
Nov-18		1.15%		-0.28%
Dec-18	145.42	1.15%	2.14%	-0.28%
Jan-19		0.85%		0.47%
Feb-19		0.85%		0.47%
Mar-19		0.85%		0.47%
Apr-19		0.85%		0.47%
May-19		0.85%		0.47%
Jun-19		0.85%		0.47%
Jul-19		0.85%		0.47%
Aug-19		0.85%		0.47%
Sep-19		0.85%		0.47%
Oct-19		0.85%		0.47%
Nov-19		0.85%		0.47%
Dec-19	160.18	0.85%	2.26%	0.47%
	Monthly Average	0.92%	Monthly Average	0.28%
	Annual Average*	11.06%	Annual Average*	3.38%

* Monthly Average times 12

Bloomberg1
S&P 500 (SPX)

Measure	Actual	F12 Est2	Growth	Y+1 Est3	Growth	Y+2 Est4	Growth
Earnings Per Share	116.57	137.51	17.96%	145.42	5.75%	160.18	10.15%

Valuation Measure	Actual	F12 Est2	Y+1 Est3	Y+2 Est4
Dividend Yield	1.97%	2.17%	2.14%	2.26%

1 Obtained from Bloomberg on August 4, 2017.

2 August 2018

3 December 2018

4 December 2019

Created on Fri 8 Sep 2017, 12:15 PM EST (17:15 GMT)

Year	Yield on 30-year Treasury bonds Source: FRB, Units: - percent per annum Last updated: 08/24/17 - 09:26
2018	3.747

LIST OF S&P 500 COMPONENT COMPANIES

(Copied from table at https://en.wikipedia.org/wiki/List_of_S&P_500_companies, October 9, 2017)

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
								Average >>	12.60%	12.15%		22,659,063.58	13.62%	18,592,560.04	12.59%
								MRP >>	9.72%	9.27%			10.74%		9.71%
	H15T30Y				2.88										
1	MMM	3M Company	Industrials	Industrial Conglomerates	215.72	4.44	8.8	11.04%	11.04%	11.04%	596.73	128,725.79	0.06%	128,725.79	0.08%
2	ABT	Abbott Laboratories	Health Care	Health Care Equipment	55.015	1.045	11.325	13.44%	13.44%	13.44%	1,472.87	81,029.90	0.05%	81,029.90	0.06%
3	ABBV	AbbVie Inc.	Health Care	Pharmaceuticals	91.92	2.35	12.1	14.97%	14.97%	14.97%	1,592.51	146,383.77	0.10%	146,383.77	0.12%
4	ACN	Accenture plc	Information Technology	IT Consulting & Other Services	137.23	2.42	10.633	12.58%	12.58%	12.58%	643.00	88,238.89	0.05%	88,238.89	0.06%
5	ATVI	Activision Blizzard	Information Technology	Home Entertainment Software	61.09	0.26	13.628	14.11%	14.11%	14.11%	745.49	45,541.78	0.03%	45,541.78	0.03%
6	AYI	Acuity Brands Inc	Industrials	Electrical Components & Equipment	167.67	0.52	16.667	17.03%	17.03%	17.03%	42.09	7,057.73	0.01%	7,057.73	0.01%
7	ADBE	Adobe Systems Inc	Information Technology	Application Software	152.5	0	19.82	19.82%	19.82%		494.25	75,373.74	0.07%		
8	AMD	Advanced Micro Devices Inc	Information Technology	Semiconductors	13.78	0	5	5.00%	5.00%		935.00	12,884.30	0.00%		
9	AAP	Advance Auto Parts	Consumer Discretionary	Automotive Retail	90.98	0.24	8.963	9.25%	9.25%	9.25%	73.75	6,709.68	0.00%	6,709.68	0.00%
10	AES	AES Corp	Utilities	Independent Power Producers & Energy Traders	11.25	0.45	8	12.32%	12.32%	12.32%	659.18	7,415.80	0.00%	7,415.80	0.00%
11	AET	Aetna Inc	Health Care	Managed Health Care	155.25	0.25	11.463	11.64%	11.64%	11.64%	351.70	54,601.43	0.03%	54,601.43	0.03%
12	AMG	Affiliated Managers Group Inc	Financials	Asset Management & Custody Banks	194.72	0	15.643	15.64%	15.64%		58.50	11,391.12	0.01%		
13	AFL	AFLAC Inc	Financials	Life & Health Insurance	83.3	1.66	2.85	4.90%	4.90%	4.90%	405.81	33,803.97	0.01%	33,803.97	0.01%
14	A	Agilent Technologies Inc	Health Care	Health Care Equipment	66.9	0.46	9.533	10.29%	10.29%	10.29%	324.00	21,675.60	0.01%	21,675.60	0.01%
15	APD	Air Products & Chemicals Inc	Materials	Industrial Gases	152.26	3.39	9.293	11.73%	11.73%	11.73%	217.35	33,093.84	0.02%	33,093.84	0.02%
16	AKAM	Akamai Technologies Inc	Information Technology	Internet Software & Services	50	0	13.4	13.40%	13.40%		173.25	8,662.74	0.01%		
17	ALK	Alaska Air Group Inc	Industrials	Airlines	81.042	1.1	6.25	7.69%	7.69%	7.69%	123.33	9,994.75	0.00%	9,994.75	0.00%
18	ALB	Albemarle Corp	Materials	Specialty Chemicals	136.8412	1.22	12.95	13.96%	13.96%	13.96%	112.52	15,397.92	0.01%	15,397.92	0.01%
19	ARE	Alexandria Real Estate Equities Inc	Real Estate	Office REITs	121.96	3.23	6.795	9.62%	9.62%	9.62%	87.67	10,691.73	0.00%	10,691.73	0.01%
20	ALXN	Alexion Pharmaceuticals	Health Care	Biotechnology	142.37	0	20.504	20.50%	20.50%		224.00	31,890.88	0.03%		
21	ALGN	Align Technology	Health Care	Health Care Supplies	190.17	0	30	30.00%	30.00%		79.50	15,118.52	0.02%		
22	ALLE	Allegion	Industrials	Building Products	87.82	0.48	13.09	13.71%	13.71%	13.71%	95.27	8,366.96	0.01%	8,366.96	0.01%
23	AGN	Allergan, Plc	Health Care	Pharmaceuticals	208.095	0	12.333	12.33%	12.33%		334.90	69,691.02	0.04%		
24	ADS	Alliance Data Systems	Information Technology	Data Processing & Outsourced Services	225.6	0	14	14.00%	14.00%		57.40	12,949.44	0.01%		
25	LNT	Alliant Energy Corp	Utilities	Electric Utilities	42.69	1.175	5.5	8.40%	8.40%	8.40%	227.67	9,719.39	0.00%	9,719.39	0.00%
26	ALL	Allstate Corp	Financials	Property & Casualty Insurance	93.01	1.32	16.267	17.92%	17.92%	17.92%	366.00	34,041.66	0.03%	34,041.66	0.03%
27	GOOGL	Alphabet Inc Class A	Information Technology	Internet Software & Services	993.29	0	16.636	16.64%	16.64%		691.29	686,654.42	0.50%		
28	GOOG	Alphabet Inc Class C	Information Technology	Internet Software & Services	977.84	#N/A Field Not Applicable	16.636	#VALUE!			#N/A Field Not Applicable				
29	MO	Altria Group Inc	Consumer Staples	Tobacco	64.975	2.35	0.707	4.35%	4.35%	4.35%	1,943.27	126,264.11	0.02%	126,264.11	0.03%
30	AMZN	Amazon.com Inc	Consumer Discretionary	Internet & Direct Marketing Retail	990.836	0	27.818	27.82%	27.82%		477.00	472,628.77	0.58%		
31	AEE	Ameren Corp	Utilities	Multi-Utilities	59.94	1.715	#N/A N/A	#VALUE!			242.60	14,541.44			
32	AAL	American Airlines Group	Industrials	Airlines	52.76	0.4	-2.49	-1.75%	-1.75%	-1.75%	507.29	26,764.84	0.00%	26,764.84	0.00%
33	AEP	American Electric Power	Utilities	Electric Utilities	73.03	2.27	5	8.26%	8.26%	8.26%	491.71	35,909.72	0.01%	35,909.72	0.02%
34	AXP	American Express Co	Financials	Consumer Finance	92.45	1.22	9.7	11.15%	11.15%	11.15%	904.00	83,574.80	0.04%	83,574.80	0.05%
35	AIG	American International Group, Inc.	Financials	Property & Casualty Insurance	61.6	1.28	11	13.31%	13.31%	13.31%	995.34	61,312.69	0.04%	61,312.69	0.04%
36	AMT	American Tower Corp A	Real Estate	Specialized REITs	137.87	2.17	20.68	22.58%	22.58%	22.58%	427.10	58,884.62	0.06%	58,884.62	0.07%
37	AWK	American Water Works Company Inc	Utilities	Water Utilities	84.32	1.5	7.95	9.87%	9.87%	9.87%	178.10	15,017.11	0.01%	15,017.11	0.01%
38	AMP	Ameriprise Financial	Financials	Asset Management & Custody Banks	150.793	2.92	10.4	12.54%	12.54%	12.54%	154.76	23,336.71	0.01%	23,336.71	0.02%
39	ABC	AmerisourceBergen Corp	Health Care	Health Care Distributors	79.5	1.36	#N/A N/A	#VALUE!			220.05	17,494.01			
40	AME	AMETEK Inc	Industrials	Electrical Components & Equipment	67.03	0.36	11.623	12.22%	12.22%	12.22%	229.38	15,375.27	0.01%	15,375.27	0.01%
41	AMGN	Amgen Inc	Health Care	Biotechnology	183.691	4	4.968	7.25%	7.25%	7.25%	738.20	135,600.70	0.04%	135,600.70	0.05%
42	APH	Amphenol Corp	Information Technology	Electronic Components	86.72	0.58	11.23	11.97%	11.97%	11.97%	308.30	26,735.78	0.01%	26,735.78	0.02%
43	APC	Anadarko Petroleum Corp	Energy	Oil & Gas Exploration & Production	48.09	0.2	-10.3	-9.93%	-9.93%	-9.93%	551.20	26,507.21	-0.01%	26,507.21	-0.01%
44	ADI	Analog Devices, Inc.	Information Technology	Semiconductors	88.09	1.66	11.55	13.65%	13.65%	13.65%	308.17	27,146.74	0.02%	27,146.74	0.02%
45	ANDV	Andeavor	Energy	Oil & Gas Refining & Marketing	106.08	2.1	18.935	21.29%	21.29%	21.29%	116.90	12,400.75	0.01%	12,400.75	0.01%
46	ANSS	ANSYS	Information Technology	Application Software	126.1705	0	12.4	12.40%	12.40%		85.69	10,811.28	0.01%		
47	ANTM	Anthem Inc.	Health Care	Managed Health Care	189.44	2.6	9.776	11.28%	11.28%	11.28%	263.75	49,964.31	0.02%	49,964.31	0.03%
48	AON	Aon plc	Financials	Insurance Brokers	147.25	1.29	11.86	12.84%	12.84%	12.84%	262.00	38,579.50	0.02%	38,579.50	0.03%
49	AOS	A.O. Smith Corp	Industrials	Building Products	60.63	0.48	15	15.91%	15.91%	15.91%	173.44	10,515.76	0.01%	10,515.76	0.01%
50	APA	Apache Corporation	Energy	Oil & Gas Exploration & Production	42.27	1	-20.21	-18.32%	-18.32%	-18.32%	379.44	16,038.92	-0.01%	16,038.92	-0.02%
51	AIV	Apartment Investment & Management	Real Estate	Residential REITs	44.99	1.32	19.067	22.56%	22.56%	22.56%	156.21	7,027.89	0.01%	7,027.89	0.01%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
52	AAPL	Apple Inc.	Information Technology	Technology Hardware, Storage & Peripherals	156.6809	2.18	10.978	12.52%	12.52%	12.52%	5,336.17	836,075.29	0.46%	836,075.29	0.56%
53	AMAT	Applied Materials Inc	Information Technology	Semiconductor Equipment	52.8	0.4	16.708	17.59%	17.59%	17.59%	1,078.00	56,918.40	0.04%	56,918.40	0.05%
54	ADM	Archer-Daniels-Midland Co	Consumer Staples	Agricultural Products	43.18	1.2	9.8	12.85%	12.85%	12.85%	573.00	24,742.14	0.01%	24,742.14	0.02%
55	ARNC	Arconic Inc	Industrials	Aerospace & Defense	27.27	0.36	16.9	18.44%	18.44%	18.44%	438.52	11,958.43	0.01%	11,958.43	0.01%
56	AJG	Arthur J. Gallagher & Co.	Financials	Insurance Brokers	61.65	1.52	10.833	13.57%	13.57%	13.57%	178.30	10,992.20	0.01%	10,992.20	0.01%
57	AIZ	Assurant Inc	Financials	Multi-line Insurance	94.05	2.03	#N/A N/A	#VALUE!			55.94	5,261.30			
58	T	AT&T Inc	Telecommunication Services	Integrated Telecommunication Services	38.55	1.93	5.25	10.52%	10.52%	10.52%	6,138.99	236,658.22	0.11%	236,658.22	0.13%
59	ADSK	Autodesk Inc	Information Technology	Application Software	117.5616	0	26	26.00%	26.00%		220.30	25,898.82	0.03%		
60	ADP	Automatic Data Processing	Information Technology	Internet Software & Services	113.24	2.24	11.475	13.68%	13.68%	13.68%	445.00	50,391.80	0.03%	50,391.80	0.04%
61	AZO	AutoZone Inc	Consumer Discretionary	Specialty Stores	583.93	0	13.31	13.31%	13.31%		27.83	16,252.52	0.01%		
62	AVB	AvalonBay Communities, Inc.	Real Estate	Residential REITs	179.745	5.4	6.423	9.62%	9.62%	9.62%	137.33	24,684.54	0.01%	24,684.54	0.01%
63	AVY	Avery Dennison Corp	Materials	Paper Packaging	101.03	1.6	7.65	9.35%	9.35%	9.35%	88.31	8,921.84	0.00%	8,921.84	0.00%
64	BHGE	Baker Hughes, a GE Company	Energy	Oil & Gas Equipment & Services	34.465	0.68	19.255	21.61%	21.61%	21.61%	#N/A N/A				
65	BLL	Ball Corp	Materials	Metal & Glass Containers	42.335	0.26	1.3	1.92%	1.92%	1.92%	349.73	14,805.83	0.00%	14,805.83	0.00%
66	BAC	Bank of America Corp	Financials	Diversified Banks	25.685	0.25	10.467	11.54%	11.54%	11.54%	10,052.63	258,201.69	0.13%	258,201.69	0.16%
67	BK	The Bank of New York Mellon Corp.	Financials	Asset Management & Custody Banks	54.53	0.72	13.24	14.74%	14.74%	14.74%	1,047.49	57,119.52	0.04%	57,119.52	0.05%
68	BCR	Bard (C.R.) Inc.	Health Care	Health Care Equipment	321.07	1.02	11	11.35%	11.35%	11.35%	72.90	23,405.76	0.01%	23,405.76	0.01%
69	BAX	Baxter International Inc.	Health Care	Health Care Equipment	61.95	1.27	13.56	15.89%	15.89%	15.89%	539.60	33,428.52	0.02%	33,428.52	0.03%
70	BBT	BB&T Corporation	Financials	Regional Banks	47.315	1.15	8.95	11.60%	11.60%	11.60%	809.48	38,300.31	0.02%	38,300.31	0.02%
71	BDX	Becton Dickinson	Health Care	Health Care Equipment	196.81	2.64	12.34	13.85%	13.85%	13.85%	213.29	41,977.85	0.03%	41,977.85	0.03%
72	BRK/B	Berkshire Hathaway	Financials	Multi-Sector Holdings	187.09	#N/A Field Not Applicable	#N/A N/A	#VALUE!			#N/A Field Not Applicable				
73	BBY	Best Buy Co. Inc.	Consumer Discretionary	Computer & Electronics Retail	56.36	1.57	12.68	15.82%	15.82%	15.82%	311.11	17,534.05	0.01%	17,534.05	0.01%
74	BIIB	Biogen Inc.	Health Care	Biotechnology	331.57	0	6.484	6.48%	6.48%		215.90	71,585.96	0.02%		
75	BLK	BlackRock	Financials	Asset Management & Custody Banks	467.52	9.16	13.73	15.96%	15.96%	15.96%	161.53	75,520.58	0.05%	75,520.58	0.06%
76	HRB	Block H&R	Financials	Consumer Finance	25.46	0.88	11	14.84%	14.84%	14.84%	207.17	5,274.57	0.00%	5,274.57	0.00%
77	BA	Boeing Company	Industrials	Aerospace & Defense	261.09	4.69	15.2	17.27%	17.27%	17.27%	617.15	161,132.11	0.12%	161,132.11	0.15%
78	BWA	BorgWarner	Consumer Discretionary	Auto Parts & Equipment	51.71	0.53	5.088	6.17%	6.17%	6.17%	212.26	10,976.12	0.00%	10,976.12	0.00%
79	BXP	Boston Properties	Real Estate	Office REITs	128.23	2.7	4.738	6.94%	6.94%	6.94%	153.79	19,720.51	0.01%	19,720.51	0.01%
80	BSX	Boston Scientific	Health Care	Health Care Equipment	29.27	0	10.333	10.33%	10.33%		1,362.10	39,868.80	0.02%		
81	BHF	Brighthouse Financial Inc	Financials	Life & Health Insurance	59.42	#N/A N/A	8	#VALUE!			#N/A N/A				
82	BMY	Bristol-Myers Squibb	Health Care	Health Care Distributors	65.42	1.53	8	10.53%	10.53%	10.53%	1,664.00	108,858.88	0.05%	108,858.88	0.06%
83	AVGO	Broadcom	Information Technology	Semiconductors	246.76	1.94	15.322	16.23%	16.23%	16.23%	398.28	98,279.93	0.07%	98,279.93	0.09%
84	BF/B	Brown-Forman Corp.	Consumer Staples	Distillers & Vintners	55.24	0.705	9.715	11.12%	11.12%	11.12%	384.21	21,223.54	0.01%	21,223.54	0.01%
85	CHRW	C. H. Robinson Worldwide	Industrials	Air Freight & Logistics	76.96	1.74	9.2	11.67%	11.67%	11.67%	141.26	10,871.22	0.01%	10,871.22	0.01%
86	CA	CA, Inc.	Information Technology	Systems Software	33.4647	1.02	2.967	6.11%	6.11%	6.11%	413.41	13,834.62	0.00%	13,834.62	0.00%
87	COG	Cabot Oil & Gas	Energy	Oil & Gas Exploration & Production	25.32	0.08	31.945	32.36%	32.36%	32.36%	465.15	11,777.60	0.02%	11,777.60	0.02%
88	CDNS	Cadence Design Systems	Information Technology	Application Software	41.35	0	11.445	11.45%	11.45%		278.10	11,499.39	0.01%		
89	CPB	Campbell Soup	Consumer Staples	Packaged Foods & Meats	46.32	1.4	4.458	7.62%	7.62%	7.62%	301.00	13,942.32	0.00%	13,942.32	0.01%
90	COF	Capital One Financial	Financials	Consumer Finance	87.2	1.6	6.19	8.14%	8.14%	8.14%	480.22	41,875.06	0.02%	41,875.06	0.02%
91	CAH	Cardinal Health Inc.	Health Care	Health Care Distributors	65.89	1.8091	12.367	15.45%	15.45%	15.45%	316.00	20,821.24	0.01%	20,821.24	0.02%
92	CBOE	CBOE Holdings	Financials	Financial Exchanges & Data	108.41	0.96	22.385	23.47%	23.47%	23.47%	81.29	8,812.14	0.01%	8,812.14	0.01%
93	KMX	Carmax Inc	Consumer Discretionary	Specialty Stores	76.17	0	13.265	13.27%	13.27%		186.55	14,209.41	0.01%		
94	CCL	Carnival Corp.	Consumer Discretionary	Hotels, Resorts & Cruise Lines	67.005	1.35	13.22	15.50%	15.50%	15.50%	726.00	48,645.63	0.03%	48,645.63	0.04%
95	CAT	Caterpillar Inc.	Industrials	Construction Machinery & Heavy Trucks	128.67	3.08	10	12.63%	12.63%	12.63%	586.49	75,463.16	0.04%	75,463.16	0.05%
96	CBG	CBRE Group	Real Estate	Real Estate Services	39.18	0	9.35	9.35%	9.35%		337.28	13,214.61	0.01%		
97	CBS	CBS Corp.	Consumer Discretionary	Broadcasting	56.7808	0.66	13.365	14.68%	14.68%	14.68%	412.00	23,393.69	0.02%	23,393.69	0.02%
98	CELG	Celgene Corp.	Health Care	Biotechnology	139.56	0	19.457	19.46%	19.46%		778.60	108,661.42	0.09%		
99	CNC	Centene Corporation	Health Care	Managed Health Care	95.3	0	12.484	12.48%	12.48%		171.92	16,383.89	0.01%		
100	CNP	CenterPoint Energy	Utilities	Multi-Utilities	29.39	1.03	6	9.71%	9.71%	9.71%	430.68	12,657.76	0.01%	12,657.76	0.01%
101	CTL	CenturyLink Inc	Telecommunication Services	Integrated Telecommunication Services	20.259	2.16	1.5	12.32%	12.32%	12.32%	546.55	11,072.46	0.01%	11,072.46	0.01%
102	CERN	Cerner	Health Care	Health Care Technology	71.535	0	12	12.00%	12.00%		329.64	23,580.90	0.01%		
103	CF	CF Industries Holdings Inc	Materials	Fertilizers & Agricultural Chemicals	34.04	1.2	6	9.74%	9.74%	9.74%	233.11	7,935.21	0.00%	7,935.21	0.00%
104	SCHW	Charles Schwab Corporation	Financials	Investment Banking & Brokerage	44.79	0.27	19.003	19.72%	19.72%	19.72%	1,332.75	59,693.87	0.05%	59,693.87	0.06%
105	CHTR	Charter Communications	Consumer Discretionary	Cable & Satellite	363.1	0	23.96	23.96%	23.96%		268.90	97,636.79	0.10%		
106	CHK	Chesapeake Energy	Energy	Oil & Gas Exploration & Production	3.82	0	-13.02	-13.02%	-13.02%		895.06	3,419.12	0.00%		
107	CVX	Chevron Corp.	Energy	Integrated Oil & Gas	118.65	4.29	42.57	47.72%	47.72%	47.72%	1,891.51	224,427.24	0.47%	224,427.24	0.58%
108	CMG	Chipotle Mexican Grill	Consumer Discretionary	Restaurants	308.31	0	50.05	50.05%	50.05%		28.81	8,883.64	0.02%		
109	CB	Chubb Limited	Financials	Property & Casualty Insurance	146.755	2.74	10.6	12.66%	12.66%	12.66%	465.97	68,383.24	0.04%	68,383.24	0.05%
110	CHD	Church & Dwight	Consumer Staples	Household Products	47.25	0.71	9.143	10.78%	10.78%	10.78%	253.96	11,999.75	0.01%	11,999.75	0.01%
111	CI	CIGNA Corp.	Health Care	Managed Health Care	186.71	0.04	12.914	12.94%	12.94%	12.94%	256.87	47,960.01	0.03%	47,960.01	0.03%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
112	XEC	Cimarex Energy	Energy	Oil & Gas Exploration & Production	115.18	0.32	63.66	64.11%	64.11%	64.11%	95.12	10,956.33	0.03%	10,956.33	0.04%
113	CINF	Cincinnati Financial	Financials	Property & Casualty Insurance	76.99	1.92	#N/A N/A	#VALUE!			164.40	12,657.16			
114	CTAS	Cintas Corporation	Industrials	Diversified Support Services	150.05	1.33	11.975	12.97%	12.97%	12.97%	105.40	15,815.36	0.01%	15,815.36	0.01%
115	CSCO	Cisco Systems	Information Technology	Communications Equipment	33.565	1.1	6.43	9.92%	9.92%	9.92%	4,983.00	167,254.40	0.07%	167,254.40	0.09%
116	C	Citigroup Inc.	Financials	Diversified Banks	74.87	0.42	12.79	13.42%	13.42%	13.42%	2,772.39	207,568.98	0.12%	207,568.98	0.15%
117	CFG	Citizens Financial Group	Financials	Regional Banks	37.29	0.46	15.11	16.53%	16.53%	16.53%	511.95	19,090.80	0.01%	19,090.80	0.02%
118	CTXS	Citrix Systems	Information Technology	Internet Software & Services	80.46	0	12.083	12.08%	12.08%		156.30	12,575.82	0.01%		
119	CLX	The Clorox Company	Consumer Staples	Household Products	129.73	3.24	6.27	8.92%	8.92%	8.92%	129.01	16,737.01	0.01%	16,737.01	0.01%
120	CME	CME Group Inc.	Financials	Financial Exchanges & Data	137.17	5.65	10.467	15.02%	15.02%	15.02%	338.24	46,396.79	0.03%	46,396.79	0.04%
121	CMS	CMS Energy	Utilities	Multi-Utilities	47.335	1.24	5	7.75%	7.75%	7.75%	279.20	13,215.93	0.00%	13,215.93	0.01%
122	COH	Coach Inc.	Consumer Discretionary	Apparel, Accessories & Luxury Goods	39.245	1.35	11.571	15.41%	15.41%	15.41%	281.90	11,063.17	0.01%	11,063.17	0.01%
123	KO	Coca-Cola Company (The)	Consumer Staples	Soft Drinks	46.085	1.4	5.613	8.82%	8.82%	8.82%	4,288.00	197,612.48	0.08%	197,612.48	0.09%
124	CTSH	Cognizant Technology Solutions	Information Technology	IT Consulting & Other Services	73.45	0	14.35	14.35%	14.35%		608.00	44,657.60	0.03%		
125	CL	Colgate-Palmolive	Consumer Staples	Household Products	74.61	1.55	9.468	11.74%	11.74%	11.74%	883.11	65,888.76	0.03%	65,888.76	0.04%
126	CMCSA	Comcast Corp.	Consumer Discretionary	Cable & Satellite	37.45	0.55	9.13	10.73%	10.73%	10.73%	4,751.60	177,947.55	0.08%	177,947.55	0.10%
127	CMA	Comerica Inc.	Financials	Diversified Banks	76.49	0.89	8	9.26%	9.26%	9.26%	175.30	13,408.70	0.01%	13,408.70	0.01%
128	CAG	Conagra Brands	Consumer Staples	Packaged Foods & Meats	33.935	0.9	7	9.84%	9.84%	9.84%	416.52	14,134.60	0.01%	14,134.60	0.01%
129	CXO	Concho Resources	Energy	Oil & Gas Exploration & Production	134.33	0	20	20.00%	20.00%		146.06	19,620.10	0.02%		
130	COP	ConocoPhillips	Energy	Oil & Gas Exploration & Production	49.1099	1	7	9.18%	9.18%	9.18%	1,237.27	60,762.17	0.02%	60,762.17	0.03%
131	ED	Consolidated Edison	Utilities	Electric Utilities	82.93	2.68	#N/A N/A	#VALUE!			305.00	25,293.65			
132	STZ	Constellation Brands	Consumer Staples	Distillers & Vintners	208.7	1.6	16.51	17.40%	17.40%	17.40%	194.60	40,612.61	0.03%	40,612.61	0.04%
133	COO	The Cooper Companies	Health Care	Health Care Supplies	235.53	0.06	9.75	9.78%	9.78%	9.78%	48.79	11,490.33	0.00%	11,490.33	0.01%
134	GLW	Corning Inc.	Information Technology	Electronic Components	29.98	0.54	8.575	10.53%	10.53%	10.53%	926.00	27,761.48	0.01%	27,761.48	0.02%
135	COST	Costco Wholesale Corp.	Consumer Staples	Hypermarkets & Super Centers	157.81	8.9	10.341	16.56%	16.56%	16.56%	437.20	68,995.16	0.05%	68,995.16	0.06%
136	COTY	Coty, Inc	Consumer Staples	Personal Products	16.8	0.65	16.995	21.52%	21.52%	21.52%	747.90	12,564.72	0.01%	12,564.72	0.01%
137	CCI	Crown Castle International Corp.	Real Estate	Specialized REITs	102.01	3.61	21.6	25.90%	25.90%	25.90%	360.54	36,778.34	0.04%	36,778.34	0.05%
138	CSRA	CSRA Inc.	Information Technology	IT Consulting & Other Services	31.72	0.4	7.55	8.91%	8.91%	8.91%	163.22	5,177.21	0.00%	5,177.21	0.00%
139	CSX	CSX Corp.	Industrials	Railroads	52.68	0.72	11.15	12.67%	12.67%	12.67%	928.18	48,896.52	0.03%	48,896.52	0.03%
140	CMI	Cummins Inc.	Industrials	Industrial Machinery	172.8	4	10.227	12.78%	12.78%	12.78%	167.50	28,944.00	0.02%	28,944.00	0.02%
141	CVS	CVS Health	Consumer Staples	Drug Retail	74.6	1.7	13.325	15.91%	15.91%	15.91%	1,061.00	79,150.60	0.06%	79,150.60	0.07%
142	DHI	D. R. Horton	Consumer Discretionary	Homebuilding	41.19	0.32	14.863	15.76%	15.76%	15.76%	372.92	15,360.71	0.01%	15,360.71	0.01%
143	DHR	Danaher Corp.	Health Care	Health Care Equipment	87.285	0.57	8.977	9.69%	9.69%	9.69%	692.20	60,418.68	0.03%	60,418.68	0.03%
144	DRI	Darden Restaurants	Consumer Discretionary	Restaurants	79.64	2.24	9.565	12.65%	12.65%	12.65%	125.40	9,986.86	0.01%	9,986.86	0.01%
145	DVA	DaVita Inc.	Health Care	Health Care Facilities	55.57	0	3.75	3.75%	3.75%		194.55	10,811.39	0.00%		
146	DE	Deere & Co.	Industrials	Agricultural & Farm Machinery	127.89	2.4	4.5	6.46%	6.46%	6.46%	314.77	40,255.66	0.01%	40,255.66	0.01%
147	DLPH	Delphi Automotive PLC	Consumer Discretionary	Auto Parts & Equipment	98.17	1.16	12.18	13.51%	13.51%	13.51%	269.79	26,485.28	0.02%	26,485.28	0.02%
148	DAL	Delta Air Lines Inc.	Industrials	Airlines	53.08	0.68	5.265	6.61%	6.61%	6.61%	730.74	38,787.56	0.01%	38,787.56	0.01%
149	XRAY	Dentsply Sirona	Health Care	Health Care Supplies	57.3	0.31	9.8	10.39%	10.39%	10.39%	230.10	13,184.73	0.01%	13,184.73	0.01%
150	DVN	Devon Energy Corp.	Energy	Oil & Gas Exploration & Production	35.78	0.42	18.415	19.81%	19.81%	19.81%	523.00	18,712.94	0.02%	18,712.94	0.02%
151	DLR	Digital Realty Trust Inc	Real Estate	Specialized REITs	120.54	3.52	5.58	8.66%	8.66%	8.66%	159.02	19,168.16	0.01%	19,168.16	0.01%
152	DFS	Discover Financial Services	Financials	Consumer Finance	64.95	1.16	3.98	5.84%	5.84%	5.84%	388.77	25,250.35	0.01%	25,250.35	0.01%
153	DISCA	Discovery Communications-A	Consumer Discretionary	Cable & Satellite	20.315	0	9.7	9.70%	9.70%		543.00	11,031.05	0.00%		
154	DISCK	Discovery Communications-C	Consumer Discretionary	Cable & Satellite	19.21	0	9.7	9.70%	9.70%		543.00	10,431.03	0.00%		
155	DISH	Dish Network	Consumer Discretionary	Cable & Satellite	51.875	0	-7.263	-7.26%	-7.26%		465.25	24,134.71	-0.01%		
156	DG	Dollar General	Consumer Discretionary	General Merchandise Stores	81.6	1	8.55	9.88%	9.88%	9.88%	275.21	22,457.30	0.01%	22,457.30	0.01%
157	DLTR	Dollar Tree	Consumer Discretionary	General Merchandise Stores	89.88	0	12.88	12.88%	12.88%		236.14	21,223.94	0.01%		
158	D	Dominion Energy	Utilities	Electric Utilities	78.09	2.8	5.6	9.39%	9.39%	9.39%	628.00	49,040.52	0.02%	49,040.52	0.02%
159	DOV	Dover Corp.	Industrials	Industrial Machinery	93.905	1.72	15.467	17.58%	17.58%	17.58%	155.43	14,595.50	0.01%	14,595.50	0.01%
160	DWDP	DowDuPont	Materials	Diversified Chemicals	71.21	0	7.825	7.83%	7.83%		#N/A N/A				
161	DPS	Dr Pepper Snapple Group	Consumer Staples	Soft Drinks	88.87	2.12	8.583	11.17%	11.17%	11.17%	183.12	16,273.86	0.01%	16,273.86	0.01%
162	DTE	DTE Energy Co.	Utilities	Multi-Utilities	109.87	3.06	5.35	8.28%	8.28%	8.28%	179.43	19,714.26	0.01%	19,714.26	0.01%
163	DRE	Duke Realty Corp	Real Estate	Industrial REITs	28.97	0.76	4.523	7.27%	7.27%	7.27%	354.76	10,277.28	0.00%	10,277.28	0.00%
164	DUK	Duke Energy	Utilities	Electric Utilities	86.4	3.36	2	5.97%	5.97%	5.97%	700.00	60,480.00	0.02%	60,480.00	0.02%
165	DXC	DXC Technology	Information Technology	IT Consulting & Other Services	87.14	0	15.25	15.25%	15.25%		283.62	24,714.21	0.02%		
166	ETFC	E*Trade	Financials	Investment Banking & Brokerage	43.75	0	16.89	16.89%	16.89%		273.96	11,985.90	0.01%		
167	EMN	Eastman Chemical	Materials	Diversified Chemicals	87.78	1.89	7.533	9.85%	9.85%	9.85%	146.44	12,854.34	0.01%	12,854.34	0.01%
168	ETN	Eaton Corporation	Industrials	Electrical Components & Equipment	78.57	2.28	10.22	13.42%	13.42%	13.42%	449.40	35,309.36	0.02%	35,309.36	0.03%
169	EBAY	eBay Inc.	Information Technology	Internet Software & Services	38.6724	0	7.628	7.63%	7.63%		1,087.00	42,036.90	0.01%		
170	ECL	Ecolab Inc.	Materials	Specialty Chemicals	131.57	1.42	12.86	14.08%	14.08%	14.08%	291.80	38,392.13	0.02%	38,392.13	0.03%
171	EIX	Edison Int'l	Utilities	Electric Utilities	78.79	1.9825	6.225	8.90%	8.90%	8.90%	325.81	25,670.66	0.01%	25,670.66	0.01%
172	EW	Edwards Lifesciences	Health Care	Health Care Equipment	110.26	0	16.68	16.68%	16.68%		211.60	23,331.02	0.02%		
173	EA	Electronic Arts	Information Technology	Home Entertainment Software	117.165	0	13.625	13.63%	13.63%		308.00	36,086.82	0.02%		
174	EMR	Emerson Electric Company	Industrials	Electrical Components & Equipment	63.417	1.9	7.45	10.67%	10.67%	10.67%	642.80	40,764.23	0.02%	40,764.23	0.02%
175	ETR	Entergy Corp.	Utilities	Electric Utilities	80.52	3.42	-3.825	0.26%	0.26%	0.26%	179.13	14,423.50	0.00%	14,423.50	0.00%
176	EVHC	Envision Healthcare	Health Care	Health Care Services	42.07	0	8.03	8.03%	8.03%		117.48	4,942.30	0.00%		
177	EOG	EOG Resources	Energy	Oil & Gas Exploration & Production	96.37	0.67	-18.26	-17.69%	-17.69%	-17.69%	576.70	55,576.58	-0.04%	55,576.58	-0.05%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
178	EQT	EQT Corporation	Energy	Oil & Gas Exploration & Production	62.83	0.12	15	15.22%	15.22%	15.22%	172.83	10,858.72	0.01%	10,858.72	0.01%
179	EFX	Equifax Inc.	Industrials	Research & Consulting Services	113.24	1.32	11.033	12.33%	12.33%	12.33%	119.90	13,577.48	0.01%	13,577.48	0.01%
180	EQIX	Equinix	Real Estate	Specialized REITs	460	8	29.252	31.50%	31.50%	31.50%	71.41	32,848.15	0.05%	32,848.15	0.06%
181	EQR	Equity Residential	Real Estate	Residential REITs	66.75	13.015	5.87	26.51%	26.51%	26.51%	365.87	24,421.88	0.03%	24,421.88	0.03%
182	ESS	Essex Property Trust, Inc.	Real Estate	Residential REITs	258.58	6.4	5.988	8.61%	8.61%	8.61%	65.53	16,944.23	0.01%	16,944.23	0.01%
183	EL	Estee Lauder Cos.	Consumer Staples	Personal Products	109.73	1.32	11.492	12.83%	12.83%	12.83%	368.10	40,391.99	0.02%	40,391.99	0.03%
184	ES	Eversource Energy	Utilities	Multi-Utilities	61.18	1.78	6.1	9.19%	9.19%	9.19%	316.89	19,387.07	0.01%	19,387.07	0.01%
185	RE	Everest Re Group Ltd	Financials	Reinsurance	222.81	4.7	10	12.32%	12.32%	12.32%	40.90	9,112.68	0.00%	9,112.68	0.01%
186	EXC	Exelon Corp.	Utilities	Multi-Utilities	38.245	1.264	3.567	6.99%	6.99%	6.99%	924.00	35,338.38	0.01%	35,338.38	0.01%
187	EXPE	Expedia Inc.	Consumer Discretionary	Internet & Direct Marketing Retail	145.67	1	17.98	18.79%	18.79%	18.79%	150.03	21,855.16	0.02%	21,855.16	0.02%
188	EXPD	Expeditors International	Industrials	Air Freight & Logistics	60.1	0.8	8.4	9.84%	9.84%	9.84%	179.86	10,809.41	0.00%	10,809.41	0.01%
189	ESRX	Express Scripts	Health Care	Health Care Distributors	58.12	0	13.275	13.28%	13.28%		605.50	35,191.66	0.02%		
190	EXR	Extra Space Storage	Real Estate	Specialized REITs	80.44	2.93	6.57	10.45%	10.45%	10.45%	125.88	10,125.90	0.00%	10,125.90	0.01%
191	XOM	Exxon Mobil Corp.	Energy	Integrated Oil & Gas	82.2129	2.98	19.49	23.82%	23.82%	23.82%	4,148.00	341,019.11	0.36%	341,019.11	0.44%
192	FFIV	F5 Networks	Information Technology	Communications Equipment	115.06	0	11.845	11.85%	11.85%		65.32	7,515.14	0.00%		
193	FB	Facebook, Inc.	Information Technology	Internet Software & Services	171.88	0	26.785	26.79%	26.79%		2,892.00	497,076.96	0.59%		
194	FAST	Fastenal Co	Industrials	Building Products	43.53	1.2	15.4	18.58%	18.58%	18.58%	289.16	12,587.22	0.01%	12,587.22	0.01%
195	FRT	Federal Realty Investment Trust	Real Estate	Retail REITs	127.74	3.84	4.67	7.82%	7.82%	7.82%	72.00	9,196.76	0.00%	9,196.76	0.00%
196	FDX	FedEx Corporation	Industrials	Air Freight & Logistics	222.43	1.6	12.72	13.53%	13.53%	13.53%	267.15	59,422.80	0.04%	59,422.80	0.04%
197	FIS	Fidelity National Information Services	Information Technology	Internet Software & Services	94.62	1.04	8.233	9.42%	9.42%	9.42%	328.00	31,035.36	0.01%	31,035.36	0.02%
198	FITB	Fifth Third Bancorp	Financials	Regional Banks	28.22	0.53	4.2	6.16%	6.16%	6.16%	750.48	21,178.53	0.01%	21,178.53	0.01%
199	FE	FirstEnergy Corp	Utilities	Electric Utilities	31.75	1.44	3.8	8.51%	8.51%	8.51%	442.34	14,044.43	0.01%	14,044.43	0.01%
200	FISV	Fiserv Inc	Information Technology	Internet Software & Services	127.525	0	10.8	10.80%	10.80%		215.50	27,481.64	0.01%		
201	FLIR	FLIR Systems	Information Technology	Electronic Equipment & Instruments	41.79	0.48	#N/A N/A	#VALUE!			137.63	5,751.52			
202	FLS	Flowserve Corporation	Industrials	Industrial Machinery	43.35	0.76	12.68	14.66%	14.66%	14.66%	129.81	5,627.39	0.00%	5,627.39	0.00%
203	FLR	Fluor Corp.	Industrials	Construction & Engineering	42.49	0.84	11.89	14.10%	14.10%	14.10%	139.26	5,917.09	0.00%	5,917.09	0.00%
204	FMC	FMC Corporation	Materials	Fertilizers & Agricultural Chemicals	91.55	0.66	12.6	13.41%	13.41%	13.41%	133.69	12,239.33	0.01%	12,239.33	0.01%
205	FL	Foot Locker Inc	Consumer Discretionary	Apparel Retail	32.9629	1.1	3.395	6.85%	6.85%	6.85%	131.50	4,334.49	0.00%	4,334.49	0.00%
206	F	Ford Motor	Consumer Discretionary	Automobile Manufacturers	12.32	0.85	-2.073	4.68%	4.68%	4.68%	3,974.30	48,963.34	0.01%	48,963.34	0.01%
207	FTV	Fortive Corp	Industrials	Industrial Machinery	72.21	0.14	9.485	9.70%	9.70%	9.70%	345.90	24,977.45	0.01%	24,977.45	0.01%
208	FBHS	Fortune Brands Home & Security	Industrials	Building Products	65.775	0.66	12.12	13.25%	13.25%	13.25%	153.41	10,090.68	0.01%	10,090.68	0.01%
209	BEN	Franklin Resources	Financials	Asset Management & Custody Banks	44.75	0.72	10	11.77%	11.77%	11.77%	570.35	25,522.95	0.01%	25,522.95	0.02%
210	FCX	Freeport-McMoRan Inc.	Materials	Copper	14.405	0	24.155	24.16%	24.16%		1,445.00	20,815.23	0.02%		
211	GPS	Gap Inc.	Consumer Discretionary	Apparel Retail	28.305	0.92	5.067	8.48%	8.48%	8.48%	399.00	11,293.70	0.00%	11,293.70	0.01%
212	GRMN	Garmin Ltd.	Consumer Discretionary	Consumer Electronics	54.12	2.04	5.675	9.66%	9.66%	9.66%	188.57	10,205.14	0.00%	10,205.14	0.01%
213	IT	Gartner Inc	Information Technology	IT Consulting & Other Services	123.9	0	17.5	17.50%	17.50%		82.65	10,240.49	0.01%		
214	GD	General Dynamics	Industrials	Aerospace & Defense	212.8	3.04	8.513	10.06%	10.06%	10.06%	302.42	64,354.66	0.03%	64,354.66	0.03%
215	GE	General Electric	Industrials	Industrial Conglomerates	23.11	0.93	11.233	15.71%	15.71%	15.71%	8,742.61	202,041.81	0.14%	202,041.81	0.17%
216	GGP	General Growth Properties Inc.	Real Estate	Retail REITs	21.74	1.06	4.65	9.75%	9.75%	9.75%	966.10	21,002.94	0.01%	21,002.94	0.01%
217	GIS	General Mills	Consumer Staples	Packaged Foods & Meats	51.14	1.92	9.567	13.68%	13.68%	13.68%	576.90	29,502.67	0.02%	29,502.67	0.02%
218	GM	General Motors	Consumer Discretionary	Automobile Manufacturers	45.1925	1.52	9.04	12.71%	12.71%	12.71%	1,500.00	67,788.75	0.04%	67,788.75	0.05%
219	GPC	Genuine Parts	Consumer Discretionary	Specialty Stores	95.38	2.63	8.915	11.92%	11.92%	11.92%	148.41	14,155.39	0.01%	14,155.39	0.01%
220	GILD	Gilead Sciences	Health Care	Biotechnology	83.055	1.84	-7.435	-5.38%	-5.38%	-5.38%	1,310.00	108,802.05	-0.03%	108,802.05	-0.03%
221	GPN	Global Payments Inc	Information Technology	Data Processing & Outsourced Services	99.44	0.04	14.5	14.55%	14.55%	14.55%	154.42	15,355.68	0.01%	15,355.68	0.01%
222	GS	Goldman Sachs Group	Financials	Investment Banking & Brokerage	241.635	2.6	10.86	12.05%	12.05%	12.05%	392.63	94,873.69	0.05%	94,873.69	0.06%
223	GT	Goodyear Tire & Rubber	Consumer Discretionary	Tires & Rubber	33.27	0.31	#N/A N/A	#VALUE!			252.00	8,384.04			
224	GWW	Grainger (W.W.) Inc.	Industrials	Industrial Machinery	170.45	4.83	9.55	12.65%	12.65%	12.65%	58.80	10,023.20	0.01%	10,023.20	0.01%
225	HAL	Halliburton Co.	Energy	Oil & Gas Equipment & Services	44.98	0.72	74	76.79%	76.79%	76.79%	866.00	38,952.68	0.13%	38,952.68	0.16%
226	HBI	Hanesbrands Inc	Consumer Discretionary	Apparel, Accessories & Luxury Goods	23.6091	0.44	10.45	12.51%	12.51%	12.51%	378.69	8,940.46	0.00%	8,940.46	0.01%
227	HOG	Harley-Davidson	Consumer Discretionary	Motorcycle Manufacturers	45.937	1.4	7.85	11.14%	11.14%	11.14%	175.95	8,082.51	0.00%	8,082.51	0.00%
228	HRS	Harris Corporation	Information Technology	Communications Equipment	136.375	2.12	#N/A N/A	#VALUE!			119.63	16,314.39			
229	HIG	Hartford Financial Svc.Gp.	Financials	Property & Casualty Insurance	55.565	0.86	9.5	11.19%	11.19%	11.19%	373.95	20,778.48	0.01%	20,778.48	0.01%
230	HAS	Hasbro Inc.	Consumer Discretionary	Leisure Products	96.145	2.04	9.7	12.03%	12.03%	12.03%	124.49	11,968.80	0.01%	11,968.80	0.01%
231	HCA	HCA Holdings	Health Care	Health Care Facilities	75.32	0	12.067	12.07%	12.07%		370.54	27,908.76	0.01%		
232	HCP	HCP Inc.	Real Estate	Health Care REITs	26.64	2.095	2.903	11.00%	11.00%	11.00%	468.08	12,469.69	0.01%	12,469.69	0.01%
233	HP	Helmerich & Payne	Energy	Oil & Gas Drilling	52.3	2.763	#N/A N/A	#VALUE!			108.08	5,652.48			
234	HSIC	Henry Schein	Health Care	Health Care Distributors	80.59	0	6	6.00%	6.00%		158.81	12,798.10	0.00%		
235	HSY	The Hershey Company	Consumer Staples	Packaged Foods & Meats	110.09	2.402	9.533	11.92%	11.92%	11.92%	212.26	23,367.67	0.01%	23,367.67	0.01%
236	HES	Hess Corporation	Energy	Integrated Oil & Gas	44.03	1	-14.735	-12.80%	-12.80%	-12.80%	316.52	13,936.52	-0.01%	13,936.52	-0.01%
237	HPE	Hewlett Packard Enterprise	Information Technology	Technology Hardware, Storage & Peripherals	14.895	0.22	-3.56	-2.14%	-2.14%	-2.14%	1,666.00	24,815.07	0.00%	24,815.07	0.00%
238	HLT	Hilton Worldwide Holdings Inc	Consumer Discretionary	Hotels, Resorts & Cruise Lines	70.3	0.84000008	15.736	17.12%	17.12%	17.12%	329.34	23,152.76	0.02%	23,152.76	0.02%
239	HOLX	Hologic	Health Care	Health Care Equipment	36.61	0	8.5	8.50%	8.50%		277.73	10,167.55	0.00%		
240	HD	Home Depot	Consumer Discretionary	Home Improvement Retail	165.35	2.76	13.693	15.59%	15.59%	15.59%	1,203.00	198,916.05	0.14%	198,916.05	0.17%
241	HON	Honeywell Int'l Inc.	Industrials	Industrial Conglomerates	142.92	2.45	10.177	12.07%	12.07%	12.07%	760.80	108,733.54	0.06%	108,733.54	0.07%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
242	HRL	Hormel Foods Corp.	Consumer Staples	Packaged Foods & Meats	31.895	0.58	6.15	8.08%	8.08%	8.08%	528.48	16,855.99	0.01%	16,855.99	0.01%
243	HST	Host Hotels & Resorts	Real Estate	Hotel & Resort REITs	18.65	0.85	4.1	8.84%	8.84%	8.84%	737.80	13,759.97	0.01%	13,759.97	0.01%
244	HPQ	HP Inc.	Information Technology	Technology Hardware, Storage & Peripherals	20.675	0.5	5.113	7.66%	7.66%	7.66%	1,712.00	35,395.60	0.01%	35,395.60	0.01%
245	HUM	Humana Inc.	Health Care	Managed Health Care	240.655	1.16	12.93	13.47%	13.47%	13.47%	149.31	35,931.04	0.02%	35,931.04	0.03%
246	HBAN	Huntington Bancshares	Financials	Regional Banks	13.84	0.29	9.435	11.73%	11.73%	11.73%	1,085.69	15,025.93	0.01%	15,025.93	0.01%
247	IDXX	IDEXX Laboratories	Health Care	Health Care Equipment	157.54	0	10.813	10.81%	10.81%		87.97	13,859.42	0.01%		
248	INFO	IHS Markit Ltd.	Industrials	Research & Consulting Services	43.94	0	13.513	13.51%	13.51%		415.00	18,235.10	0.01%		
249	ITW	Illinois Tool Works	Industrials	Industrial Machinery	151.14	2.4	9.2	10.93%	10.93%	10.93%	346.90	52,430.47	0.03%	52,430.47	0.03%
250	ILMN	Illumina Inc	Health Care	Life Sciences Tools & Services	204.21	0	15.477	15.48%	15.48%		146.20	29,854.69	0.02%		
251	IR	Ingersoll-Rand PLC	Industrials	Industrial Machinery	91.28	1.36	11.04	12.69%	12.69%	12.69%	259.01	23,642.10	0.01%	23,642.10	0.02%
252	INTC	Intel Corp.	Information Technology	Semiconductors	39.24	1.04	8.14	11.01%	11.01%	11.01%	4,730.00	185,605.20	0.09%	185,605.20	0.11%
253	ICE	Intercontinental Exchange	Financials	Financial Exchanges & Data	69.84	0.68	10.975	12.06%	12.06%	12.06%	595.00	41,554.80	0.02%	41,554.80	0.03%
254	IBM	International Business Machines	Information Technology	IT Consulting & Other Services	148.08	5.5	2.375	6.18%	6.18%	6.18%	945.87	140,064.05	0.04%	140,064.05	0.05%
255	INCY	Incyte	Health Care	Biotechnology	113.9263	0	44.045	44.05%	44.05%		188.85	21,514.84	0.04%		
256	IP	International Paper	Materials	Paper Packaging	57.76	1.7825	7.225	10.53%	10.53%	10.53%	412.23	23,810.35	0.01%	23,810.35	0.01%
257	IPG	Interpublic Group	Consumer Discretionary	Advertising	20.75	0.6	10.19	13.38%	13.38%	13.38%	391.60	8,125.70	0.00%	8,125.70	0.01%
258	IFF	Intl Flavors & Fragrances	Materials	Specialty Chemicals	147.195	2.4	4	5.70%	5.70%	5.70%	79.21	11,659.76	0.00%	11,659.76	0.00%
259	INTU	Intuit Inc.	Information Technology	Internet Software & Services	144.1	1.36	14.88	15.96%	15.96%	15.96%	255.67	36,841.76	0.03%	36,841.76	0.03%
260	ISRG	Intuitive Surgical Inc.	Health Care	Health Care Equipment	356.87	0	10.048	10.05%	10.05%		116.40	41,539.67	0.02%		
261	IVZ	Invesco Ltd.	Financials	Asset Management & Custody Banks	36.23	1.11	12.963	16.42%	16.42%	16.42%	403.80	14,629.67	0.01%	14,629.67	0.01%
262	IRM	Iron Mountain Incorporated	Real Estate	Specialized REITs	38.94	2.0427	14.6	20.61%	20.61%	20.61%	263.68	10,267.80	0.01%	10,267.80	0.01%
263	JEC	Jacobs Engineering Group	Industrials	Construction & Engineering	58.13	0	8.73	8.73%	8.73%		120.95	7,030.88	0.00%		
264	JBHT	J. B. Hunt Transport Services	Industrials	Trucking	106.38	0.88	13.35	14.29%	14.29%	14.29%	111.31	11,840.63	0.01%	11,840.63	0.01%
265	SJM	JM Smucker	Consumer Staples	Packaged Foods & Meats	104.61	3	3.963	6.94%	6.94%	6.94%	113.44	11,866.91	0.00%	11,866.91	0.00%
266	JNJ	Johnson & Johnson	Health Care	Health Care Equipment	136.48	3.15	6.034	8.48%	8.48%	8.48%	2,706.51	369,384.62	0.14%	369,384.62	0.17%
267	JCI	Johnson Controls International	Industrials	Building Products	41.39	1.16	8.467	11.51%	11.51%	11.51%	935.80	38,732.59	0.02%	38,732.59	0.02%
268	JPM	JPMorgan Chase & Co.	Financials	Diversified Banks	96.2001	1.88	3	5.01%	5.01%	5.01%	3,561.19	342,586.82	0.08%	342,586.82	0.09%
269	JNPR	Juniper Networks	Information Technology	Communications Equipment	26.44	0.4	8.25	9.89%	9.89%	9.89%	381.10	10,076.28	0.00%	10,076.28	0.01%
270	KSU	Kansas City Southern	Industrials	Railroads	104.87	1.32	14	15.43%	15.43%	15.43%	106.61	11,179.84	0.01%	11,179.84	0.01%
271	K	Kellogg Co.	Consumer Staples	Packaged Foods & Meats	61.92	2.04	6.23	9.73%	9.73%	9.73%	351.07	21,738.21	0.01%	21,738.21	0.01%
272	KEY	KeyCorp	Financials	Regional Banks	18.49	0.33	10.9	12.88%	12.88%	12.88%	1,079.31	19,956.52	0.01%	19,956.52	0.01%
273	KMB	Kimberly-Clark	Consumer Staples	Household Products	117.39	3.68	6.223	9.55%	9.55%	9.55%	356.60	41,861.27	0.02%	41,861.27	0.02%
274	KIM	Kimco Realty	Real Estate	Retail REITs	19.545	1.035	19.963	26.32%	26.32%	26.32%	425.03	8,307.29	0.01%	8,307.29	0.01%
275	KMI	Kinder Morgan	Energy	Oil & Gas Storage & Transportation	19	0.5	20	23.16%	23.16%	23.16%	2,230.10	42,371.95	0.04%	42,371.95	0.05%
276	KLAC	KLA-Tencor Corp.	Information Technology	Semiconductor Equipment	104.6875	2.14	7.9	10.11%	10.11%	10.11%	156.84	16,419.19	0.01%	16,419.19	0.01%
277	KSS	Kohl's Corp.	Consumer Discretionary	General Merchandise Stores	43.04	2	5.45	10.35%	10.35%	10.35%	187.00	8,048.48	0.00%	8,048.48	0.00%
278	KHC	Kraft Heinz Co	Consumer Staples	Packaged Foods & Meats	78.42	2.35	7.712	10.94%	10.94%	10.94%	1,216.48	95,396.03	0.05%	95,396.03	0.06%
279	KR	Kroger Co.	Consumer Staples	Food Retail	21.725	0.465	5.166	7.42%	7.42%	7.42%	924.00	20,073.90	0.01%	20,073.90	0.01%
280	LB	L Brands Inc.	Consumer Discretionary	Apparel Retail	42.22	4.4	7.54	18.75%	18.75%	18.75%	286.00	12,074.92	0.01%	12,074.92	0.01%
281	LLL	L-3 Communications Holdings	Industrials	Aerospace & Defense	187.69	2.8	6.415	8.00%	8.00%	8.00%	77.23	14,495.71	0.01%	14,495.71	0.01%
282	LH	Laboratory Corp. of America Holding	Health Care	Health Care Services	149.66	0	11.35	11.35%	11.35%		102.70	15,370.08	0.01%		
283	LRCX	Lam Research	Information Technology	Semiconductor Equipment	184.84	1.65	7.7	8.66%	8.66%	8.66%	161.72	29,892.88	0.01%	29,892.88	0.01%
284	LEG	Leggett & Platt	Consumer Discretionary	Home Furnishings	47.825	1.34	19	22.33%	22.33%	22.33%	133.50	6,384.64	0.01%	6,384.64	0.01%
285	LEN	Lennar Corp.	Consumer Discretionary	Homebuilding	56.23	0.16	12.477	12.80%	12.80%	12.80%	234.48	13,184.54	0.01%	13,184.54	0.01%
286	LVLT	Level 3 Communications	Telecommunication Services	Alternative Carriers	55.42	0	5	5.00%	5.00%		360.02	19,952.37	0.00%		
287	LUK	Leucadia National Corp.	Financials	Multi-Sector Holdings	25.13	0.25	18	19.17%	19.17%	19.17%	359.43	9,032.35	0.01%	9,032.35	0.01%
288	LLY	Lilly (Eli) & Co.	Health Care	Pharmaceuticals	86.02	2.05	8.5	11.09%	11.09%	11.09%	1,100.88	94,697.27	0.05%	94,697.27	0.06%
289	LNC	Lincoln National	Financials	Multi-line Insurance	74.56	1.04	9.25	10.77%	10.77%	10.77%	226.34	16,875.55	0.01%	16,875.55	0.01%
290	LKQ	LKQ Corporation	Consumer Discretionary	Distributors	36.81	0	12.5	12.50%	12.50%		307.54	11,320.72	0.01%		
291	LMT	Lockheed Martin Corp.	Industrials	Aerospace & Defense	318.24	6.77	9.418	11.75%	11.75%	11.75%	289.00	91,971.36	0.05%	91,971.36	0.06%
292	L	Loews Corp.	Financials	Multi-line Insurance	48.61	0.25	#N/A N/A	#VALUE!			336.62	16,363.16			
293	LOW	Lowe's Cos.	Consumer Discretionary	Home Improvement Retail	81.335	1.33	14.378	16.25%	16.25%	16.25%	866.00	70,436.11	0.05%	70,436.11	0.06%
294	LYB	LyondellBasell	Materials	Specialty Chemicals	97.42	3.33	6.5	10.14%	10.14%	10.14%	404.05	39,362.19	0.02%	39,362.19	0.02%
295	MTB	M&T Bank Corp.	Financials	Regional Banks	162.24	2.8	9.255	11.14%	11.14%	11.14%	156.22	25,344.74	0.01%	25,344.74	0.02%
296	MAC	Macerich	Real Estate	Retail REITs	58.03	2.75	7.605	12.70%	12.70%	12.70%	143.99	8,355.45	0.00%	8,355.45	0.01%
297	M	Macy's Inc.	Consumer Discretionary	Department Stores	20.53	1.4925	-0.475	6.76%	6.76%	6.76%	304.10	6,243.17	0.00%	6,243.17	0.00%
298	MRO	Marathon Oil Corp.	Energy	Oil & Gas Exploration & Production	13.48	0.2	5	6.56%	6.56%	6.56%	847.00	11,417.56	0.00%	11,417.56	0.00%
299	MPC	Marathon Petroleum	Energy	Oil & Gas Refining & Marketing	56.215	1.36	12.68	15.41%	15.41%	15.41%	528.00	29,681.52	0.02%	29,681.52	0.02%
300	MAR	Marriott Int'l.	Consumer Discretionary	Hotels, Resorts & Cruise Lines	114.19	1.15	15.118	16.28%	16.28%	16.28%	386.10	44,088.76	0.03%	44,088.76	0.04%
301	MMC	Marsh & McLennan	Financials	Insurance Brokers	83.44	1.3	12.86	14.62%	14.62%	14.62%	514.49	42,929.15	0.03%	42,929.15	0.03%
302	MLM	Martin Marietta Materials	Materials	Construction Materials	205.62	1.64	21.237	22.20%	22.20%	22.20%	63.18	12,990.25	0.01%	12,990.25	0.02%
303	MAS	Masco Corp.	Industrials	Building Products	38.785	0.37	14.325	15.42%	15.42%	15.42%	318.00	12,333.63	0.01%	12,333.63	0.01%
304	MA	Mastercard Inc.	Information Technology	Internet Software & Services	146.52	0.76	16.625	17.23%	17.23%	17.23%	1,081.00	158,388.12	0.12%	158,388.12	0.15%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
305	MAT	Mattel Inc.	Consumer Discretionary	Leisure Products	15.555	1.52	11.3	22.18%	22.18%	22.18%	342.40	5,326.03	0.01%	5,326.03	0.01%
306	MKC	McCormick & Co.	Consumer Staples	Packaged Foods & Meats	98.01	1.72	9.6	11.52%	11.52%	11.52%	125.30	12,280.65	0.01%	12,280.65	0.01%
307	MCD	McDonald's Corp.	Consumer Discretionary	Restaurants	162.85	3.61	10.09	12.53%	12.53%	12.53%	819.30	133,423.01	0.07%	133,423.01	0.09%
308	MCK	McKesson Corp.	Health Care	Health Care Distributors	149.979	1.12	5.3	6.09%	6.09%	6.09%	211.00	31,645.57	0.01%	31,645.57	0.01%
309	MDT	Medtronic plc	Health Care	Health Care Equipment	77.4453	1.72	6.43	8.79%	8.79%	8.79%	1,369.42	106,055.52	0.04%	106,055.52	0.05%
310	MRK	Merck & Co.	Health Care	Pharmaceuticals	63.97	1.85	6.067	9.13%	9.13%	9.13%	2,748.73	175,836.34	0.07%	175,836.34	0.09%
311	MET	MetLife Inc.	Financials	Life & Health Insurance	52.64	1.575	35.9	39.97%	39.97%	39.97%	1,095.52	57,668.12	0.10%	57,668.12	0.12%
312	MTD	Mettler Toledo	Health Care	Life Sciences Tools & Services	658.16	0	12.25	12.25%	12.25%		26.02	17,125.48	0.01%		
313	MGM	MGM Resorts International	Consumer Discretionary	Casinos & Gaming	30.41	0	17.46	17.46%	17.46%		574.12	17,459.10	0.01%		
314	KORS	Michael Kors Holdings	Consumer Discretionary	Apparel, Accessories & Luxury Goods	46.96	0	7	7.00%	7.00%		155.83	7,317.93	0.00%		
315	MCHP	Microchip Technology	Information Technology	Semiconductors	91.495	1.441	17.055	18.90%	18.90%	18.90%	229.09	20,960.92	0.02%	20,960.92	0.02%
316	MU	Micron Technology	Information Technology	Semiconductors	41.39	0	0.833	0.83%	0.83%		1,114.07	46,111.19	0.00%		
317	MSFT	Microsoft Corp.	Information Technology	Systems Software	76.155	1.56	10.544	12.81%	12.81%	12.81%	7,708.00	587,002.74	0.33%	587,002.74	0.40%
318	MAA	Mid-America Apartments	Real Estate	Residential REITs	109.04	3.33	#N/A N/A	#VALUE!			113.52	12,378.03			
319	MHK	Mohawk Industries	Consumer Discretionary	Home Furnishings	254.87	0	8.483	8.48%	8.48%		74.17	18,903.20	0.01%		
320	TAP	Molson Coors Brewing Company	Consumer Staples	Brewers	83.79	1.64	7.21	9.31%	9.31%	9.31%	224.40	18,802.48	0.01%	18,802.48	0.01%
321	MDLZ	Mondelez International	Consumer Staples	Packaged Foods & Meats	41.64	0.72	11.64	13.57%	13.57%	13.57%	1,528.37	63,641.14	0.04%	63,641.14	0.05%
322	MON	Monsanto Co.	Materials	Fertilizers & Agricultural Chemicals	119.62	2.16	6.233	8.15%	8.15%	8.15%	439.32	52,551.82	0.02%	52,551.82	0.02%
323	MNST	Monster Beverage	Consumer Staples	Soft Drinks	55.74	0	20.3	20.30%	20.30%		566.57	31,580.39	0.03%		
324	MCO	Moody's Corp	Financials	Financial Exchanges & Data	142.69	1.49	#N/A N/A	#VALUE!			190.69	27,210.13			
325	MS	Morgan Stanley	Financials	Investment Banking & Brokerage	49.18	0.7	16.31	17.97%	17.97%	17.97%	1,852.48	91,105.05	0.07%	91,105.05	0.09%
326	MOS	The Mosaic Company	Materials	Fertilizers & Agricultural Chemicals	21.1001	1.1	11.7	17.52%	17.52%	17.52%	350.24	7,390.07	0.01%	7,390.07	0.01%
327	MSI	Motorola Solutions Inc.	Information Technology	Communications Equipment	89.3	1.7	4.1	6.08%	6.08%	6.08%	164.70	14,707.71	0.00%	14,707.71	0.00%
328	MYL	Mylan N.V.	Health Care	Pharmaceuticals	38.41	0	3.6	3.60%	3.60%		535.33	20,561.95	0.00%		
329	NDAQ	Nasdaq, Inc.	Financials	Financial Exchanges & Data	74.96	1.21	9.08	10.84%	10.84%	10.84%	166.58	12,486.80	0.01%	12,486.80	0.01%
330	NOV	National Oilwell Varco Inc.	Energy	Oil & Gas Equipment & Services	34.51	0.61	#N/A N/A	#VALUE!			378.64	13,066.78			
331	NAVI	Navient	Financials	Consumer Finance	12.175	0.64	#N/A N/A	#VALUE!			290.86	3,541.27			
332	NTAP	NetApp	Information Technology	Internet Software & Services	43.9	0.76	9.9	11.80%	11.80%	11.80%	269.00	11,809.10	0.01%	11,809.10	0.01%
333	NFLX	Netflix Inc.	Information Technology	Internet Software & Services	195.06	0	40.6	40.60%	40.60%		430.05	83,886.37	0.15%		
334	NWL	Newell Brands	Consumer Discretionary	Housewares & Specialties	42.06	0.76	11.323	13.33%	13.33%	13.33%	482.50	20,293.95	0.01%	20,293.95	0.01%
335	NFX	Newfield Exploration Co	Energy	Oil & Gas Exploration & Production	29.92	0	12.19	12.19%	12.19%		198.95	5,952.72	0.00%		
336	NEM	Newmont Mining Corporation	Materials	Gold	38.24	0.125	-11.65	-11.36%	-11.36%	-11.36%	531.00	20,305.44	-0.01%	20,305.44	-0.01%
337	NWSA	News Corp. Class A	Consumer Discretionary	Publishing	13.39	0.1	12.59	13.43%	13.43%	13.43%	581.92	7,791.97	0.00%	7,791.97	0.01%
338	NWS	News Corp. Class B	Consumer Discretionary	Publishing	13.725	#N/A Field Not Applicable	12.59	#VALUE!			#N/A Field Not Applicable				
339	NEE	NextEra Energy	Utilities	Multi-Utilities	150.22	3.48	6.67	9.14%	9.14%	9.14%	468.00	70,302.96	0.03%	70,302.96	0.03%
340	NLSN	Nielsen Holdings	Industrials	Research & Consulting Services	40.405	1.21	10	13.29%	13.29%	13.29%	357.47	14,443.40	0.01%	14,443.40	0.01%
341	NKE	Nike	Consumer Discretionary	Apparel, Accessories & Luxury Goods	51.19	0.7	8.498	9.98%	9.98%	9.98%	1,643.00	84,105.17	0.04%	84,105.17	0.05%
342	NI	NiSource Inc.	Utilities	Multi-Utilities	26.46	0.64	6.1	8.67%	8.67%	8.67%	323.16	8,550.80	0.00%	8,550.80	0.00%
343	NBL	Noble Energy Inc	Energy	Oil & Gas Exploration & Production	27.4	0.4	3.715	5.23%	5.23%	5.23%	433.36	11,874.08	0.00%	11,874.08	0.00%
344	JWN	Nordstrom	Consumer Discretionary	Department Stores	42.95	1.48	6	9.65%	9.65%	9.65%	170.00	7,301.50	0.00%	7,301.50	0.00%
345	NSC	Norfolk Southern Corp.	Industrials	Railroads	130.48	2.36	13.567	15.62%	15.62%	15.62%	290.42	37,893.69	0.03%	37,893.69	0.03%
346	NTRS	Northern Trust Corp.	Financials	Asset Management & Custody Banks	93.1	1.48	11.895	13.67%	13.67%	13.67%	228.61	21,283.17	0.01%	21,283.17	0.02%
347	NOC	Northrop Grumman Corp.	Industrials	Aerospace & Defense	294.05	3.5	7.673	8.95%	8.95%	8.95%	175.07	51,478.82	0.02%	51,478.82	0.02%
348	NRG	NRG Energy	Utilities	Independent Power Producers & Energy Traders	25.505	0.24	#N/A N/A	#VALUE!			315.44	8,045.37			
349	NUE	Nucor Corp.	Materials	Steel	56.45	1.5025	12	14.98%	14.98%	14.98%	318.74	17,992.70	0.01%	17,992.70	0.01%
350	NVDA	Nvidia Corporation	Information Technology	Semiconductors	189.31	0.485	12.52	12.81%	12.81%	12.81%	585.00	110,746.35	0.06%	110,746.35	0.08%
351	ORLY	O'Reilly Automotive	Consumer Discretionary	Specialty Stores	208.29	0	15.323	15.32%	15.32%		92.85	19,340.10	0.01%		
352	OXY	Occidental Petroleum	Energy	Oil & Gas Exploration & Production	64.31	3.02	-3.385	1.15%	1.15%	1.15%	764.24	49,148.10	0.00%	49,148.10	0.00%
353	OMC	Omnicom Group	Consumer Discretionary	Advertising	74.48	2.15	6.973	10.06%	10.06%	10.06%	234.70	17,480.46	0.01%	17,480.46	0.01%
354	OKE	ONEOK	Energy	Oil & Gas Storage & Transportation	56.14	2.46	13.25	18.21%	18.21%	18.21%	210.68	11,827.67	0.01%	11,827.67	0.01%
355	ORCL	Oracle Corp.	Information Technology	Application Software	48.36	0.64	8.371	9.81%	9.81%	9.81%	4,137.00	200,065.32	0.09%	200,065.32	0.11%
356	PCAR	PACCAR Inc.	Industrials	Construction Machinery & Heavy Trucks	73.18	1.56	6.733	9.01%	9.01%	9.01%	350.70	25,664.23	0.01%	25,664.23	0.01%
357	PKG	Packaging Corporation of America	Materials	Paper Packaging	117.45	2.36	8.25	10.43%	10.43%	10.43%	94.20	11,063.79	0.01%	11,063.79	0.01%
358	PH	Parker-Hannifin	Industrials	Industrial Machinery	177.37	2.58	11.88	13.51%	13.51%	13.51%	133.19	23,624.20	0.01%	23,624.20	0.02%
359	PDCO	Patterson Companies	Health Care	Health Care Supplies	36.95	0.98	9.1	11.99%	11.99%	11.99%	96.53	3,566.93	0.00%	3,566.93	0.00%
360	PAYX	Paychex Inc.	Information Technology	Internet Software & Services	63.62	1.84	8.275	11.41%	11.41%	11.41%	359.40	22,865.03	0.01%	22,865.03	0.01%
361	PYPL	PayPal	Information Technology	Data Processing & Outsourced Services	67.66	0	19.862	19.86%	19.86%		1,207.00	81,665.62	0.07%		
362	PNR	Pentair Ltd.	Industrials	Industrial Machinery	69.99	1.34	8.04	10.11%	10.11%	10.11%	181.80	12,724.18	0.01%	12,724.18	0.01%
363	PBCT	People's United Financial	Financials	Thrifts & Mortgage Finance	18.2	0.6775	2	5.80%	5.80%	5.80%	308.90	5,621.98	0.00%	5,621.98	0.00%
364	PEP	PepsiCo Inc.	Consumer Staples	Soft Drinks	111.281	2.96	6.21	9.04%	9.04%	9.04%	1,428.00	158,909.27	0.06%	158,909.27	0.08%
365	PKI	PerkinElmer	Health Care	Health Care Equipment	71.74	0.28	10.42	10.85%	10.85%	10.85%	109.62	7,863.92	0.00%	7,863.92	0.00%
366	PRGO	Perrigo	Health Care	Pharmaceuticals	87.33	0.58	5.967	6.67%	6.67%	6.67%	143.40	12,523.12	0.00%	12,523.12	0.00%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
367	PFE	Pfizer Inc.	Health Care	Pharmaceuticals	36.325	1.2	8.433	12.02%	12.02%	12.02%	6,070.00	220,492.75	0.12%	220,492.75	0.14%
368	PCG	PG&E Corp.	Utilities	Multi-Utilities	69.33	1.93	#N/A N/A	#VALUE!			506.89	35,142.81			
369	PM	Philip Morris International	Consumer Staples	Tobacco	114.496	4.12	9.687	13.63%	13.63%	13.63%	1,551.39	177,627.44	0.11%	177,627.44	0.13%
370	PSX	Phillips 66	Energy	Oil & Gas Refining & Marketing	93.31	2.45	-3.74	-1.21%	-1.21%	-1.21%	518.77	48,406.11	0.00%	48,406.11	0.00%
371	PNW	Pinnacle West Capital	Utilities	Multi-Utilities	86.55	2.53	5.5	8.58%	8.58%	8.58%	111.34	9,636.19	0.00%	9,636.19	0.00%
372	PXD	Pioneer Natural Resources	Energy	Oil & Gas Exploration & Production	148.46	0.08	20	20.06%	20.06%	20.06%	169.72	25,197.23	0.02%	25,197.23	0.03%
373	PNC	PNC Financial Services	Financials	Regional Banks	135.84	2.12	9.58	11.29%	11.29%	11.29%	485.00	65,882.40	0.03%	65,882.40	0.04%
374	RL	Polo Ralph Lauren Corp.	Consumer Discretionary	Apparel, Accessories & Luxury Goods	85.605	2	0.287	2.63%	2.63%	2.63%	81.00	6,934.01	0.00%	6,934.01	0.00%
375	PPG	PPG Industries	Materials	Specialty Chemicals	112.02	1.56	8.093	9.60%	9.60%	9.60%	257.33	28,826.12	0.01%	28,826.12	0.01%
376	PPL	PPL Corp.	Utilities	Electric Utilities	38.03	1.52	#N/A N/A	#VALUE!			679.73	25,850.17			
377	PX	Praxair Inc.	Materials	Industrial Gases	140.32	3	10.35	12.71%	12.71%	12.71%	284.90	39,977.31	0.02%	39,977.31	0.03%
378	PCLN	Priceline.com Inc	Consumer Discretionary	Internet & Direct Marketing Retail	1909.145	0	17.26	17.26%	17.26%		49.19	93,907.63	0.07%		
379	PFG	Principal Financial Group	Financials	Life & Health Insurance	67.01	1.61	10.4	13.05%	13.05%	13.05%	287.70	19,278.78	0.01%	19,278.78	0.01%
380	PG	Procter & Gamble	Consumer Staples	Personal Products	91.28	2.7	7.177	10.35%	10.35%	10.35%	2,553.30	233,064.95	0.11%	233,064.95	0.13%
381	PGR	Progressive Corp.	Financials	Property & Casualty Insurance	49.095	0.6808	11.833	13.38%	13.38%	13.38%	579.90	28,470.19	0.02%	28,470.19	0.02%
382	PLD	Prologis	Real Estate	Industrial REITs	64.47	1.68	6.31	9.08%	9.08%	9.08%	524.51	33,815.29	0.01%	33,815.29	0.02%
383	PRU	Prudential Financial	Financials	Life & Health Insurance	109.58	2.8	8	10.76%	10.76%	10.76%	429.57	47,072.74	0.02%	47,072.74	0.03%
384	PEG	Public Serv. Enterprise Inc.	Utilities	Electric Utilities	48.13	1.64	2.9	6.41%	6.41%	6.41%	505.00	24,305.65	0.01%	24,305.65	0.01%
385	PSA	Public Storage	Real Estate	Specialized REITs	212.29	7.3	5.45	9.08%	9.08%	9.08%	173.29	36,787.48	0.01%	36,787.48	0.02%
386	PHM	Pulte Homes Inc.	Consumer Discretionary	Homebuilding	26.8	0.36	18.4	19.99%	19.99%	19.99%	319.09	8,551.60	0.01%	8,551.60	0.01%
387	PVH	PVH Corp.	Consumer Discretionary	Apparel, Accessories & Luxury Goods	125.44	0.15	10.955	11.09%	11.09%	11.09%	78.55	9,853.50	0.00%	9,853.50	0.01%
388	QRVO	Qorvo	Information Technology	Semiconductors	72.28	0	13.183	13.18%	13.18%		126.46	9,140.82	0.01%		
389	PWR	Quanta Services Inc.	Industrials	Construction & Engineering	37.4999	0	8	8.00%	8.00%		144.71	5,426.64	0.00%		
390	QCOM	QUALCOMM Inc.	Information Technology	Semiconductors	54.25	2.02	8.748	12.80%	12.80%	12.80%	1,476.00	80,073.00	0.05%	80,073.00	0.06%
391	DGX	Quest Diagnostics	Health Care	Health Care Services	91.105	1.65	6.95	8.89%	8.89%	8.89%	137.00	12,481.39	0.00%	12,481.39	0.01%
392	Q	Quintiles IMS Holdings, Inc	Health Care	Life Sciences Tools & Service	96.95	0	14.333	14.33%	14.33%		248.30	24,072.69	0.02%		
393	RRC	Range Resources Corp.	Energy	Oil & Gas Exploration & Production	19.965	0.08	-19.59	-19.27%	-19.27%	-19.27%	247.14	4,934.24	0.00%	4,934.24	-0.01%
394	RJF	Raymond James Financial Inc.	Financials	Investment Banking & Brokerage	86.15	0.8	15.45	16.52%	16.52%	16.52%	141.66	12,203.85	0.01%	12,203.85	0.01%
395	RTN	Raytheon Co.	Industrials	Aerospace & Defense	186.68	2.87	8.413	10.08%	10.08%	10.08%	293.00	54,697.24	0.02%	54,697.24	0.03%
396	O	Realty Income Corporation	Real Estate	Retail REITs	56.81	2.3915	4.42	8.82%	8.82%	8.82%	260.17	14,780.16	0.01%	14,780.16	0.01%
397	RHT	Red Hat Inc.	Information Technology	Systems Software	118.45	0	17	17.00%	17.00%		176.90	20,954.03	0.02%		
398	REG	Regency Centers Corporation	Real Estate	Retail REITs	63.99	2	9.263	12.68%	12.68%	12.68%	104.15	6,664.52	0.00%	6,664.52	0.00%
399	REGN	Regeneron	Health Care	Biotechnology	451.995	0	18.003	18.00%	18.00%		106.01	47,915.16	0.04%		
400	RF	Regions Financial Corp.	Financials	Regional Banks	14.93	0.255	12.37	14.29%	14.29%	14.29%	1,214.58	18,133.69	0.01%	18,133.69	0.01%
401	RSG	Republic Services Inc	Industrials	Environmental & Facilities Services	63.46	1.24	11.213	13.39%	13.39%	13.39%	339.40	21,538.32	0.01%	21,538.32	0.02%
402	RMD	ResMed	Health Care	Health Care Equipment	76.375	1.32	12.5	14.44%	14.44%	14.44%	142.17	10,858.59	0.01%	10,858.59	0.01%
403	RHI	Robert Half International	Industrials	Human Resource & Employment Services	49.44	0.88	8.3	10.23%	10.23%	10.23%	127.80	6,318.26	0.00%	6,318.26	0.00%
404	ROK	Rockwell Automation Inc.	Industrials	Electrical Components & Equipment	183.048	2.9	11.474	13.24%	13.24%	13.24%	128.50	23,521.67	0.01%	23,521.67	0.02%
405	COL	Rockwell Collins	Industrials	Aerospace & Defense	134.1075	1.32	10.727	11.82%	11.82%	11.82%	130.20	17,460.80	0.01%	17,460.80	0.01%
406	ROP	Roper Technologies	Industrials	Industrial Conglomerates	250.72	1.25	12.933	13.50%	13.50%	13.50%	101.67	25,491.20	0.02%	25,491.20	0.02%
407	ROST	Ross Stores	Consumer Discretionary	Apparel Retail	64.795	0.54	13.6	14.55%	14.55%	14.55%	391.89	25,392.71	0.02%	25,392.71	0.02%
408	RCL	Royal Caribbean Cruises Ltd	Consumer Discretionary	Hotels, Resorts & Cruise Lines	125.01	1.71	19.097	20.73%	20.73%	20.73%	214.59	26,826.43	0.02%	26,826.43	0.03%
409	CRM	Salesforce.com	Information Technology	Internet Software & Services	95.56	0	28.05	28.05%	28.05%		707.46	67,604.88	0.08%		
410	SBAC	SBA Communications Corp	Real Estate	Specialized REITs	149.89	0	23.05	23.05%	23.05%		121.00	18,137.29	0.02%		
411	SCG	SCANA Corp	Utilities	Multi-Utilities	49.72	2.3	2.567	7.31%	7.31%	7.31%	143.00	7,109.96	0.00%	7,109.96	0.00%
412	SLB	Schlumberger Ltd.	Energy	Oil & Gas Equipment & Services	67.215	2	41.707	45.92%	45.92%	45.92%	1,391.00	93,496.07	0.19%	93,496.07	0.23%
413	SNI	Scripps Networks Interactive Inc.	Consumer Discretionary	Cable & Satellite	85.26	1	9.19	10.47%	10.47%	10.47%	129.34	11,027.70	0.01%	11,027.70	0.01%
414	STX	Seagate Technology	Information Technology	Technology Hardware, Storage & Peripherals	33.71	2.52	8.55	16.66%	16.66%	16.66%	291.80	9,836.56	0.01%	9,836.56	0.01%
415	SEE	Sealed Air	Materials	Paper Packaging	44.53	0.61	8.115	9.60%	9.60%	9.60%	193.48	8,615.77	0.00%	8,615.77	0.00%
416	SRE	Sempra Energy	Utilities	Multi-Utilities	115.33	3.02	14.25	17.24%	17.24%	17.24%	250.00	28,832.50	0.02%	28,832.50	0.03%
417	SHW	Sherwin-Williams	Materials	Specialty Chemicals	380.19	3.36	11.335	12.32%	12.32%	12.32%	93.01	35,362.62	0.02%	35,362.62	0.02%
418	SIG	Signet Jewelers	Consumer Discretionary	Specialty Stores	65.79	1.04	3.4	5.03%	5.03%	5.03%	68.30	4,493.46	0.00%	4,493.46	0.00%
419	SPG	Simon Property Group Inc	Real Estate	Retail REITs	164.24	6.5	7.055	11.29%	11.29%	11.29%	313.08	51,419.44	0.03%	51,419.44	0.03%
420	SWKS	Skyworks Solutions	Information Technology	Semiconductors	104.93	1.06	13.594	14.74%	14.74%	14.74%	184.90	19,401.56	0.01%	19,401.56	0.02%
421	SLG	SL Green Realty	Real Estate	Office REITs	104.965	2.935	0.637	3.45%	3.45%	3.45%	100.56	10,555.49	0.00%	10,555.49	0.00%
422	SNA	Snap-On Inc.	Consumer Discretionary	Household Appliances	150.06	2.54	10.85	12.73%	12.73%	12.73%	57.95	8,695.96	0.00%	8,695.96	0.01%
423	SO	Southern Co.	Utilities	Electric Utilities	50.54	2.2225	2	6.49%	6.49%	6.49%	990.20	50,044.71	0.01%	50,044.71	0.02%
424	LUV	Southwest Airlines	Industrials	Airlines	58.75	0.375	6.31	6.99%	6.99%	6.99%	647.60	38,046.59	0.01%	38,046.59	0.01%
425	SPGI	S&P Global, Inc.	Financials	Financial Exchanges & Data	158.43	1.44	10	11.00%	11.00%	11.00%	259.00	41,033.37	0.02%	41,033.37	0.02%
426	SWK	Stanley Black & Decker	Consumer Discretionary	Household Appliances	155.207	2.26	11	12.62%	12.62%	12.62%	152.56	23,678.34	0.01%	23,678.34	0.02%
427	SBUX	Starbucks Corp.	Consumer Discretionary	Restaurants	55.38	0.85	16.517	18.31%	18.31%	18.31%	1,460.50	80,882.49	0.07%	80,882.49	0.08%
428	STT	State Street Corp.	Financials	Asset Management & Custody Banks	98.725	1.44	12.37	14.01%	14.01%	14.01%	381.94	37,706.94	0.02%	37,706.94	0.03%
429	SRCL	Stericycle Inc	Industrials	Environmental & Facilities Services	70.415	0	7.675	7.68%	7.68%		85.15	5,996.03	0.00%		
430	SYK	Stryker Corp.	Health Care	Health Care Equipment	146.34	1.52	9.225	10.36%	10.36%	10.36%	375.00	54,877.50	0.03%	54,877.50	0.03%
431	STI	SunTrust Banks	Financials	Regional Banks	60.28	1	9.315	11.13%	11.13%	11.13%	491.19	29,608.81	0.01%	29,608.81	0.02%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
432	SYMC	Symantec Corp.	Information Technology	Application Software	31.56	0.3	13.14	14.22%	14.22%	14.22%	608.02	19,189.08	0.01%	19,189.08	0.01%
433	SYF	Synchrony Financial	Financials	Consumer Finance	31.4564	0.26	8.093	8.99%	8.99%	8.99%	817.35	25,710.96	0.01%	25,710.96	0.01%
434	SNPS	Synopsys Inc.	Information Technology	Application Software	83.16	0	9.12	9.12%	9.12%		151.45	12,594.91	0.01%		
435	SYY	Sysco Corp.	Consumer Staples	Food Distributors	54.145	1.3	10.04	12.68%	12.68%	12.68%	530.04	28,698.97	0.02%	28,698.97	0.02%
436	TROW	T. Rowe Price Group	Financials	Asset Management & Custody Banks	92.46	2.16	12.735	15.37%	15.37%	15.37%	244.78	22,632.73	0.02%	22,632.73	0.02%
437	TGT	Target Corp.	Consumer Discretionary	General Merchandise Stores	58.96	2.36	-0.777	3.19%	3.19%	3.19%	556.16	32,790.97	0.00%	32,790.97	0.01%
438	TEL	TE Connectivity Ltd.	Information Technology	Electronic Manufacturing Services	86.34	1.4	6.865	8.60%	8.60%	8.60%	355.28	30,674.99	0.01%	30,674.99	0.01%
439	FTI	TechnipFMC	Energy	Oil & Gas Equipment & Services	26.89	0	8.59	8.59%	8.59%		467.22	12,563.59	0.00%		
440	TXN	Texas Instruments	Information Technology	Semiconductors	92.37	1.64	10.525	12.49%	12.49%	12.49%	995.98	91,999.04	0.05%	91,999.04	0.06%
441	TXT	Textron Inc.	Industrials	Aerospace & Defense	54.2	0.08	8.78	8.94%	8.94%	8.94%	270.30	14,650.26	0.01%	14,650.26	0.01%
442	TMO	Thermo Fisher Scientific	Health Care	Health Care Equipment	192.93	0.6	13	13.35%	13.35%	13.35%	393.45	75,907.90	0.04%	75,907.90	0.05%
443	TIF	Tiffany & Co.	Consumer Discretionary	Apparel, Accessories & Luxury Goods	92.71	1.75	10.1	12.18%	12.18%	12.18%	124.50	11,542.40	0.01%	11,542.40	0.01%
444	TWX	Time Warner Inc.	Consumer Discretionary	Cable & Satellite	103.78	1.61	8.3	9.98%	9.98%	9.98%	772.00	80,118.16	0.04%	80,118.16	0.04%
445	TJX	TJX Companies Inc.	Consumer Discretionary	Apparel Retail	72.57	1.04	10.65	12.24%	12.24%	12.24%	646.32	46,903.37	0.03%	46,903.37	0.03%
446	TMK	Torchmark Corp.	Financials	Life & Health Insurance	80.43	0.56	8	8.75%	8.75%	8.75%	118.03	9,493.24	0.00%	9,493.24	0.00%
447	TSS	Total System Services	Information Technology	Internet Software & Services	67.74	0.4	11.138	11.79%	11.79%	11.79%	183.45	12,426.97	0.01%	12,426.97	0.01%
448	TSCO	Tractor Supply Company	Consumer Discretionary	Specialty Stores	60	0.92	13.65	15.39%	15.39%	15.39%	130.80	7,847.70	0.01%	7,847.70	0.01%
449	TDG	TransDigm Group	Industrials	Aerospace & Defense	266.63	0	10.213	10.21%	10.21%		51.82	13,815.94	0.01%		
450	TRV	The Travelers Companies Inc.	Financials	Property & Casualty Insurance	125.732	2.62	11.575	13.90%	13.90%	13.90%	279.60	35,154.67	0.02%	35,154.67	0.03%
451	TRIP	TripAdvisor	Consumer Discretionary	Internet & Direct Marketing Retail	41.44	0	14.496	14.50%	14.50%		144.11	5,971.96	0.00%		
452	FOXA	Twenty-First Century Fox Class A	Consumer Discretionary	Publishing	26.485	0.36	9.227	10.71%	10.71%	10.71%	1,851.06	49,025.27	0.02%	49,025.27	0.03%
453	FOX	Twenty-First Century Fox Class B	Consumer Discretionary	Publishing	25.92	0.36	9.227	10.74%	10.74%	10.74%	1,851.06	47,979.42	0.02%	47,979.42	0.03%
454	TSN	Tyson Foods	Consumer Staples	Packaged Foods & Meats	70.0701	0.65	8.6	9.61%	9.61%	9.61%	361.00	25,295.31	0.01%	25,295.31	0.01%
455	UDR	UDR Inc	Real Estate	Residential REITs	38.74	1.18	6.127	9.36%	9.36%	9.36%	267.26	10,353.63	0.00%	10,353.63	0.01%
456	ULTA	Ulta Salon Cosmetics & Fragrance Inc	Consumer Discretionary	Specialty Stores	208.81	0	21.6	21.60%	21.60%		62.13	12,973.16	0.01%		
457	USB	U.S. Bancorp	Financials	Diversified Banks	53.89	1.07	12.13	14.36%	14.36%	14.36%	1,696.91	91,446.60	0.06%	91,446.60	0.07%
458	UA	Under Armour Class C	Consumer Discretionary	Apparel, Accessories & Luxury Goods	15.2162	#N/A Field Not Applicable	9.677	#VALUE!			#N/A Field Not Applicable				
459	UAA	Under Armour Class A	Consumer Discretionary	Apparel, Accessories & Luxury Goods	16.42	0	13.172	13.17%	13.17%		438.44	7,199.17	0.00%		
460	UNP	Union Pacific	Industrials	Railroads	113	2.255	11.633	13.86%	13.86%	13.86%	815.82	92,188.16	0.06%	92,188.16	0.07%
461	UAL	United Continental Holdings	Industrials	Airlines	67.98	0	0.295	0.30%	0.30%		314.61	21,387.37	0.00%		
462	UNH	United Health Group Inc.	Health Care	Managed Health Care	194.58	2.375	12.15	13.52%	13.52%	13.52%	952.00	185,240.16	0.11%	185,240.16	0.13%
463	UPS	United Parcel Service	Industrials	Air Freight & Logistics	118.51	3.12	11.9	14.85%	14.85%	14.85%	868.00	102,866.68	0.07%	102,866.68	0.08%
464	URI	United Rentals, Inc.	Industrials	Trading Companies & Distributors	141.35	0	14.173	14.17%	14.17%		84.22	11,904.79	0.01%		
465	UTX	United Technologies	Industrials	Aerospace & Defense	117.7	2.62	8.723	11.14%	11.14%	11.14%	808.70	95,184.11	0.05%	95,184.11	0.06%
466	UHS	Universal Health Services, Inc.	Health Care	Health Care Facilities	107	0.4	8.69	9.10%	9.10%	9.10%	96.63	10,339.44	0.00%	10,339.44	0.01%
467	UNM	Unum Group	Financials	Life & Health Insurance	51.97	0.77	5	6.56%	6.56%	6.56%	229.82	11,943.90	0.00%	11,943.90	0.00%
468	VFC	V.F. Corp.	Consumer Discretionary	Apparel, Accessories & Luxury Goods	64.3801	1.53	7.96	10.53%	10.53%	10.53%	414.01	26,654.20	0.01%	26,654.20	0.02%
469	VLO	Valero Energy	Energy	Oil & Gas Refining & Marketing	77.37	2.4	10.45	13.88%	13.88%	13.88%	451.50	34,932.68	0.02%	34,932.68	0.03%
470	VAR	Varian Medical Systems	Health Care	Health Care Equipment	101.035	0	7.2	7.20%	7.20%		93.70	9,466.98	0.00%		
471	VTR	Ventas Inc	Real Estate	Health Care REITs	63.49	2.965	3.033	7.84%	7.84%	7.84%	354.12	22,483.33	0.01%	22,483.33	0.01%
472	VRSN	Verisign Inc.	Information Technology	Internet Software & Services	108.3	0	10.2	10.20%	10.20%		103.09	11,164.76	0.01%		
473	VRSK	Verisk Analytics	Industrials	Research & Consulting Services	83.66	0	7.957	7.96%	7.96%		166.92	13,964.17	0.00%		
474	VZ	Verizon Communications	Telecommunication Services	Integrated Telecommunication Services	49.185	2.285	1.923	6.66%	6.66%	6.66%	4,076.68	200,511.71	0.06%	200,511.71	0.07%
475	VRTX	Vertex Pharmaceuticals Inc	Health Care	Biotechnology	153.045	0	72.498	72.50%	72.50%		248.30	38,001.15	0.12%		
476	VIAB	Viacom Inc.	Consumer Discretionary	Cable & Satellite	25.45	1.4	2.96	8.62%	8.62%	8.62%	397.00	10,103.65	0.00%	10,103.65	0.00%
477	V	Visa Inc.	Information Technology	Internet Software & Services	108.47	0.56	16.758	17.36%	17.36%	17.36%	2,343.00	254,145.21	0.19%	254,145.21	0.24%
478	VNO	Vornado Realty Trust	Real Estate	Office REITs	79.3325	2.52	-0.83	2.32%	2.32%	2.32%	189.10	15,001.85	0.00%	15,001.85	0.00%
479	VMC	Vulcan Materials	Materials	Construction Materials	118.38	0.8	21.823	22.65%	22.65%	22.65%	132.34	15,666.29	0.02%	15,666.29	0.02%
480	WMT	Wal-Mart Stores	Consumer Staples	Hypermarkets & Super Centers	84.8858	2	5.285	7.77%	7.77%	7.77%	3,048.00	258,731.92	0.09%	258,731.92	0.11%
481	WBA	Walgreens Boots Alliance	Consumer Staples	Drug Retail	69.49	1.455	9.033	11.32%	11.32%	11.32%	1,082.99	75,256.74	0.04%	75,256.74	0.05%
482	DIS	The Walt Disney Company	Consumer Discretionary	Cable & Satellite	98.89	1.42	7.19	8.73%	8.73%	8.73%	1,600.00	158,224.00	0.06%	158,224.00	0.07%
483	WM	Waste Management Inc.	Industrials	Environmental & Facilities Services	76.88	1.64	10.09	12.44%	12.44%	12.44%	439.32	33,774.60	0.02%	33,774.60	0.02%
484	WAT	Waters Corporation	Health Care	Health Care Distributors	185.96	0	8.274	8.27%	8.27%		80.02	14,881.08	0.01%		
485	WEC	Wec Energy Group Inc	Utilities	Electric Utilities	65.08	1.98	5.55	8.76%	8.76%	8.76%	315.61	20,540.22	0.01%	20,540.22	0.01%
486	WFC	Wells Fargo	Financials	Diversified Banks	55.41	1.515	11.455	14.50%	14.50%	14.50%	5,016.11	277,942.62	0.18%	277,942.62	0.22%
487	HCN	Welltower Inc.	Real Estate	Health Care REITs	68.01	3.44	2.61	7.80%	7.80%	7.80%	388.48	26,420.33	0.01%	26,420.33	0.01%
488	WDC	Western Digital	Information Technology	Technology Hardware, Storage & Peripherals	86.64	2	11.473	14.05%	14.05%	14.05%	294.00	25,472.16	0.02%	25,472.16	0.02%
489	WU	Western Union Co	Information Technology	Internet Software & Services	19.58	0.64	8	11.53%	11.53%	11.53%	481.50	9,427.77	0.00%	9,427.77	0.01%
490	WRK	WestRock Company	Materials	Paper Packaging	58.62	1.5	9.667	12.47%	12.47%	12.47%	251.00	14,713.62	0.01%	14,713.62	0.01%
491	WY	Weyerhaeuser Corp.	Real Estate	Specialized REITs	34.46	1.24	7.4	11.26%	11.26%	11.26%	748.53	25,794.28	0.01%	25,794.28	0.02%
492	WHR	Whirlpool Corp.	Consumer Discretionary	Household Appliances	176.81	3.9	14.19	16.71%	16.71%	16.71%	74.00	13,083.94	0.01%	13,083.94	0.01%

	Ticker symbol	Security	GICS Sector	GICS Sub Industry	Price	Dividend	LTG	DCF ROE	DCF ROE All	DCF ROE Div. Paid	Shares	Mkt Cap	DCF ROE +MC All	Mkt Cap	DCF ROE +MC Div. Paid
493	WMB	Williams Cos.	Energy	Oil & Gas Storage & Transportation	29.9962	1.68	2.9	8.66%	8.66%	8.66%	750.00	22,497.15	0.01%	22,497.15	0.01%
494	WLTW	Willis Towers Watson	Financials	Insurance Brokers	155.665	1.92	10	11.36%	11.36%	11.36%	135.54	21,098.98	0.01%	21,098.98	0.01%
495	WYN	Wyndham Worldwide	Consumer Discretionary	Hotels, Resorts & Cruise Lines	109.22	2	14.25	16.34%	16.34%	16.34%	105.58	11,531.55	0.01%	11,531.55	0.01%
496	WYNN	Wynn Resorts Ltd	Consumer Discretionary	Casinos & Gaming	143.58	2	31.9	33.74%	33.74%	33.74%	101.80	14,616.37	0.02%	14,616.37	0.03%
497	XEL	Xcel Energy Inc	Utilities	Multi-Utilities	48.33	1.36	6.05	9.03%	9.03%	9.03%	507.22	24,514.08	0.01%	24,514.08	0.01%
498	XRX	Xerox Corp.	Information Technology	Technology Hardware, Storage & Peripherals	32.75	1.24	2.9	6.80%	6.80%	6.80%	253.59	8,305.20	0.00%	8,305.20	0.00%
499	XLNX	Xilinx Inc	Information Technology	Semiconductors	72.49	1.32	8.367	10.34%	10.34%	10.34%	248.03	17,979.48	0.01%	17,979.48	0.01%
500	XL	XL Capital	Financials	Property & Casualty Insurance	38.96	0.8	9	11.24%	11.24%	11.24%	266.89	10,398.00	0.01%	10,398.00	0.01%
501	XYL	Xylem Inc.	Industrials	Industrial Machinery	64.48	0.6196	15	16.11%	16.11%	16.11%	179.50	11,574.16	0.01%	11,574.16	0.01%
502	YUM	Yum! Brands Inc	Consumer Discretionary	Restaurants	76.87	3.62	12.74	18.05%	18.05%	18.05%	355.00	27,288.85	0.02%	27,288.85	0.03%
503	ZBH	Zimmer Biomet Holdings	Health Care	Health Care Equipment	117.9	0.96	8.38	9.26%	9.26%	9.26%	200.60	23,650.74	0.01%	23,650.74	0.01%
504	ZION	Zions Bancorp	Financials	Regional Banks	47.22	0.28	9	9.65%	9.65%	9.65%	203.09	9,589.68	0.00%	9,589.68	0.00%
505	ZTS	Zoetis	Health Care	Pharmaceuticals	63.9901	0.39	14.75	15.45%	15.45%	15.45%		0.00	0.00%	0.00	0.00%

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Southern California Edison Company	)	**Dkt. No. ER18-______-000**
	)	

EXHIBIT SCE-21

EXHIBIT TO THE TESTIMONY OF DR. PAUL T. HUNT

ON BEHALF OF SOUTHERN CALIFORNIA EDISON COMPANY

OCTOBER 2017

WHY COST OF CAPITAL MUST ACCOUNT FOR AMORTIZATIONS

DEBT COST

Assumptions:		
Issuance (Face Value):		100,000,000
Maturity (in Years)		30
Coupon		5.00%
Issuance Costs		
Discount	0.05%	50,000
Expense	0.09%	90,000
Total Issuance Cost		140,000
Net Proceeds from Issuance		99,860,000
Total Annual Cost of Debt Service		5,004,667
Annual Cost/Face Value		5.0047%

Debt Cost

(A) Year	(B) Interest Expense	(C) Amortization (Issuance Costs /Maturity)	(D) Total Cost of Debt Service	(E) Annual Cost/ Face Value	(F) Net Proceeds (Mid-Year)	(G) Annual Cost/ Net Proceeds
0					99,860,000	
1	5,000,000	4,667	5,004,667	5.0047%	99,862,333	5.0116%
2	5,000,000	4,667	5,004,667	5.0047%	99,867,000	5.0113%
3	5,000,000	4,667	5,004,667	5.0047%	99,871,667	5.0111%
4	5,000,000	4,667	5,004,667	5.0047%	99,876,333	5.0109%
5	5,000,000	4,667	5,004,667	5.0047%	99,881,000	5.0106%
6	5,000,000	4,667	5,004,667	5.0047%	99,885,667	5.0104%
7	5,000,000	4,667	5,004,667	5.0047%	99,890,333	5.0102%
8	5,000,000	4,667	5,004,667	5.0047%	99,895,000	5.0099%
9	5,000,000	4,667	5,004,667	5.0047%	99,899,667	5.0097%
10	5,000,000	4,667	5,004,667	5.0047%	99,904,333	5.0095%
11	5,000,000	4,667	5,004,667	5.0047%	99,909,000	5.0092%
12	5,000,000	4,667	5,004,667	5.0047%	99,913,667	5.0090%
13	5,000,000	4,667	5,004,667	5.0047%	99,918,333	5.0088%
14	5,000,000	4,667	5,004,667	5.0047%	99,923,000	5.0085%
15	5,000,000	4,667	5,004,667	5.0047%	99,927,667	5.0083%
16	5,000,000	4,667	5,004,667	5.0047%	99,932,333	5.0081%
17	5,000,000	4,667	5,004,667	5.0047%	99,937,000	5.0078%
18	5,000,000	4,667	5,004,667	5.0047%	99,941,667	5.0076%
19	5,000,000	4,667	5,004,667	5.0047%	99,946,333	5.0074%
20	5,000,000	4,667	5,004,667	5.0047%	99,951,000	5.0071%
21	5,000,000	4,667	5,004,667	5.0047%	99,955,667	5.0069%
22	5,000,000	4,667	5,004,667	5.0047%	99,960,333	5.0067%
23	5,000,000	4,667	5,004,667	5.0047%	99,965,000	5.0064%
24	5,000,000	4,667	5,004,667	5.0047%	99,969,667	5.0062%
25	5,000,000	4,667	5,004,667	5.0047%	99,974,333	5.0060%
26	5,000,000	4,667	5,004,667	5.0047%	99,979,000	5.0057%
27	5,000,000	4,667	5,004,667	5.0047%	99,983,667	5.0055%
28	5,000,000	4,667	5,004,667	5.0047%	99,988,333	5.0053%
29	5,000,000	4,667	5,004,667	5.0047%	99,993,000	5.0050%
30	5,000,000	4,667	5,004,667	5.0047%	99,997,667	5.0048%
Total						

WHY COST OF CAPITAL MUST ACCOUNT FOR AMORTIZATIONS

TOTAL CAPITAL COST AND RECOVERY OF CAPITAL COST

Assumptions:	
Common Equity Outstanding (Book Value)	100,000,000
Long-Term Debt Outstanding (Face Value)	100,000,000

Weighted Average Cost of Capital (Book Value/Face Value)

Cost of Equity	10.30%
Cost of Debt (Face Value)	5.0047%
Equity Ratio (Book Value/Face Value)	50.00%
Weighted Average Cost of Capital (WACC)	7.65233%

	Total Capital Cost			**Recovery of Capital Cost At Book Value/Face Value (7.65233%) WACC**			**Recovery of Capital Cost At Net Proceeds WACC**			
(A)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)
Year	Total Equity Cost	Total Debt Cost	Total Cost of Capital	Rate Base	Return at Book Value/ Face Value WACC	Under-/Over-Recovery	Rate Base	Net Proceeds WACC	Return at Book Value/ Face Value WACC	Under-/Over-Recovery
0										
1	10,300,000	5,004,667	15,304,667	199,862,333	15,294,132	-10,535	199,862,333	7.6576%	15,304,667	0
2	10,300,000	5,004,667	15,304,667	199,867,000	15,294,489	-10,178	199,867,000	7.6574%	15,304,667	0
3	10,300,000	5,004,667	15,304,667	199,871,667	15,294,846	-9,820	199,871,667	7.6572%	15,304,667	0
4	10,300,000	5,004,667	15,304,667	199,876,333	15,295,203	-9,463	199,876,333	7.6571%	15,304,667	0
5	10,300,000	5,004,667	15,304,667	199,881,000	15,295,560	-9,106	199,881,000	7.6569%	15,304,667	0
6	10,300,000	5,004,667	15,304,667	199,885,667	15,295,917	-8,749	199,885,667	7.6567%	15,304,667	0
7	10,300,000	5,004,667	15,304,667	199,890,333	15,296,275	-8,392	199,890,333	7.6565%	15,304,667	0
8	10,300,000	5,004,667	15,304,667	199,895,000	15,296,632	-8,035	199,895,000	7.6564%	15,304,667	0
9	10,300,000	5,004,667	15,304,667	199,899,667	15,296,989	-7,678	199,899,667	7.6562%	15,304,667	0
10	10,300,000	5,004,667	15,304,667	199,904,333	15,297,346	-7,321	199,904,333	7.6560%	15,304,667	0
11	10,300,000	5,004,667	15,304,667	199,909,000	15,297,703	-6,964	199,909,000	7.6558%	15,304,667	0
12	10,300,000	5,004,667	15,304,667	199,913,667	15,298,060	-6,607	199,913,667	7.6556%	15,304,667	0
13	10,300,000	5,004,667	15,304,667	199,918,333	15,298,417	-6,249	199,918,333	7.6555%	15,304,667	0
14	10,300,000	5,004,667	15,304,667	199,923,000	15,298,774	-5,892	199,923,000	7.6553%	15,304,667	0
15	10,300,000	5,004,667	15,304,667	199,927,667	15,299,131	-5,535	199,927,667	7.6551%	15,304,667	0
16	10,300,000	5,004,667	15,304,667	199,932,333	15,299,489	-5,178	199,932,333	7.6549%	15,304,667	0
17	10,300,000	5,004,667	15,304,667	199,937,000	15,299,846	-4,821	199,937,000	7.6547%	15,304,667	0
18	10,300,000	5,004,667	15,304,667	199,941,667	15,300,203	-4,464	199,941,667	7.6546%	15,304,667	0
19	10,300,000	5,004,667	15,304,667	199,946,333	15,300,560	-4,107	199,946,333	7.6544%	15,304,667	0
20	10,300,000	5,004,667	15,304,667	199,951,000	15,300,917	-3,750	199,951,000	7.6542%	15,304,667	0
21	10,300,000	5,004,667	15,304,667	199,955,667	15,301,274	-3,393	199,955,667	7.6540%	15,304,667	0
22	10,300,000	5,004,667	15,304,667	199,960,333	15,301,631	-3,035	199,960,333	7.6539%	15,304,667	0
23	10,300,000	5,004,667	15,304,667	199,965,000	15,301,988	-2,678	199,965,000	7.6537%	15,304,667	0
24	10,300,000	5,004,667	15,304,667	199,969,667	15,302,345	-2,321	199,969,667	7.6535%	15,304,667	0
25	10,300,000	5,004,667	15,304,667	199,974,333	15,302,703	-1,964	199,974,333	7.6533%	15,304,667	0
26	10,300,000	5,004,667	15,304,667	199,979,000	15,303,060	-1,607	199,979,000	7.6531%	15,304,667	0
27	10,300,000	5,004,667	15,304,667	199,983,667	15,303,417	-1,250	199,983,667	7.6530%	15,304,667	0
28	10,300,000	5,004,667	15,304,667	199,988,333	15,303,774	-893	199,988,333	7.6528%	15,304,667	0
29	10,300,000	5,004,667	15,304,667	199,993,000	15,304,131	-536	199,993,000	7.6526%	15,304,667	0
30	10,300,000	5,004,667	15,304,667	199,997,667	15,304,488	-179	199,997,667	7.6524%	15,304,667	0
Total						-160,699				0