SOUTHERN CALIFORNIA
EDISON
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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Southern California Edison Company **Docket No. ER19-_____-000**

SOUTHERN CALIFORNIA EDISON COMPANY

TRANSMISSION OWNER TARIFF
TRANSMISSION RATE FILING
(TO2019A)

VOLUME 1

GENERAL INFORMATION

APRIL 2019

SOUTHERN CALIFORNIA EDISON
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TRANSMITTAL LETTER

SOUTHERN CALIFORNIA
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April 11, 2019

Hon. Kimberly D. Bose, Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

RE: Southern California Edison Company
Docket No. ER19- ____- 000

Southern California Edison Company's
Transmission Owner Tariff Rate Filing

Dear Ms. Bose:

Pursuant to Section 205(d) of the Federal Power Act, 16 U.S.C. § 824d (2012), and Section 35.13 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations (18 C.F.R § 35.13), Southern California Edison Company ("SCE") tenders for filing revisions to its Transmission Owner Tariff ("TO Tariff"), FERC Electric Tariff, Volume No. 6. The filing amends the formula rate for the costs associated with SCE's transmission facilities.

SCE is making this filing due to dramatic material changes to SCE's regulatory and financial conditions that have occurred since SCE filed its currently effective Formula Rate (the "Second Formula Rate") in October 2017.[1] Beginning in December

[1] On October 27, 2017, SCE filed its Second Formula Rate ("Second Formula Rate") in Docket No. ER18-169. On December 29, 2017, the Commission accepted the Second Formula Rate and related 2018 base Transmission Revenue Requirement, established that is effective January 1, 2018 subject to refund and established hearing and settlement judge procedures

2017, several wind-driven wildfires impacted portions of SCE's service territory and caused substantial damage to both residential and business properties and service outages for some of SCE's customers. California has unique inverse condemnation laws. These laws provide that an electric utility will be held strictly liable for property damages and legal fees if its facilities are the substantial cause of a fire regardless of fault and even if the utility was fully compliant with all applicable rules and regulations, and acted reasonably. As a result of these laws and recent fires, SCE is exposed to significant potential wildfire damage claims. In 2017, the California Public Utilities Commission ("CPUC") issued a decision holding that it could preclude a utility from recovering these court-assigned costs if it finds the utility was not prudent, even if the source of the alleged imprudent conduct was not directly the cause of the fire.[2] The decision creates significant CPUC-related cost-recovery uncertainty and, as a result, SCE recently announced an accrual of a 2018 fourth quarter non-cash charge against earnings of $1.8 billion due to potential wildfire damages that would be dependent upon CPUC-approval.[3]

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and instituted a Section 206 proceeding. *Southern California Edison Co.*, 161 FERC 61,309 (2017). As of the date of this filing, it remains in settlement proceedings.

[2] CPUC Decision (D.)17-11-033, *Decision Denying Application* (issued December 6, 2017); reh'g denied, D.18-07-025 *Order Denying Rehearing of D.17-11-033* (July 12, 2018). The CPUC's standard of review is not the same as this Commission's standard of review. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 143 FERC ¶ 61,149 at P 121 (2013).

[3] EIX and SCE 2018 Annual Report on Form 10-K, as required by the U.S. Securities and Exchange Commission ("SEC"), which includes financial statements covering the period Jan. 1, 2018 – Dec. 31, 2018 ("2018 10-K").

The stock of SCE's parent company, Edison International ("EIX"), has dropped dramatically since 2017 as a result of this wildfire risk. On January 21, 2019, Standard & Poor's ("S&P") downgraded SCE from BBB+ to BBB. And on February 18, 2019, S&P issued a report entitled "Will California Still Have an Investment-Grade Investor Owned Electric Utility?" in which they warned that further downgrades should be expected unless there is regulatory action to address wildfire risks to the utilities. On March 5, 2019, Moody's Investors Services ("Moody's") downgraded SCE's credit ratings including its senior unsecured rating to Baa2 from A3. This means that SCE is near the bottom of the investment grade category. Moody's based this downgrade on "the potential for multi-billion dollar exposure related to wildfire risk that is unique to investor-owned utilities in California."[4] Moody's also classified SCE as "outlook negative" meaning that SCE is at risk of further downgrades if the legal and regulatory environment in California remains unchanged.

SCE is aggressively pursuing steps to strengthen its system and manage risks to protect against wildfire threats. SCE is investing significant amounts of capital to harden

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[4] Moody's Investors Service, Rating Action: Moody's downgrades Edison International to Baa3 and Southern California Edison to Baa2; outlooks negative (March 5, 2019). Moody's explained that California has unique wildfire risks because "wildfires are on average much more destructive because of its higher population density compared to other western states" and because of the doctrine of inverse condemnation, which "holds electric utilities to a strict liability standard on third-party property damages caused by the wildfire, regardless of fault" when utility equipment is a substantial cause of the wildfire. Moody's also referenced the "significant amount of uncertainty associated with the cost recovery process because in 2017 the CPUC disallowed the entire $379 million wildfire cost request for wildfires that occurred on San Diego Gas & Electric's territory in 2007."

its system to reduce wildfire risk, with the goal of ensuring safety and maintaining reliability. At the same time, SCE is pursuing legislative, regulatory and legal strategies to address the application of a strict liability standard to wildfire-related damages and the prudency standard applied by the CPUC to determine whether a utility can recover these court-assigned costs. However, SCE cannot predict whether or when a comprehensive solution mitigating the significant risk faced by California utilities related to wildfires will be achieved. Accordingly, SCE is filing proposed revisions to its Formula Rate to account for this risk in a manner sufficient to attract the capital necessary to provide safe and reliable electric service.

I. BACKGROUND

On April 1, 1998, SCE unbundled its retail transmission rates and transferred Operational Control of its network transmission facilities to the California Independent System Operator Corporation ("CAISO"). As the result of these events, the Commission gained jurisdiction over SCE's retail transmission rates, complementing its existing jurisdiction over SCE's wholesale transmission rates. SCE filed its Transmission Owner Tariff ("TO Tariff") and its first proposed Base Transmission Revenue Requirement ("Base TRR")[5] on March 31, 1997 in Docket No. ER97-2355.

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5 The Base TRR reflects SCE's costs of owning and operating its transmission facilities that are under the CAISO's Operational Control.

From April 1, 1997 through December 31, 2011, SCE's Base TRR was established through "Stated Rate" TRR filings.[6] On June 3, 2011, SCE filed a TRR filing requesting a formula rate in Docket No. ER11-3697. The filing was accepted and suspended, set for hearing and settlement procedures, and given a January 1, 2012 effective date. The parties to Docket No. ER11-3697 engaged in settlement negotiations and the Commission approved the settlement on October 11, 2013. Since January 1, 2012, SCE's Base TRR has been established pursuant to the Original Formula Rate, with Annual Update filings being submitted each year covering a calendar year term. The protocols to the Original Formula Rate required SCE to file a replacement rate mechanism to recover SCE's Commission-jurisdictional transmission costs no later than 60 days prior to January 1, 2018 and request an effective date of January 1, 2018 in that filing. On October 27, 2017, SCE submitted this filing, proposing the Second Formula Rate in Docket No. ER18-169.

By order dated December 29, 2017, the Commission accepted SCE's TO2018 Formula Rate and related 2018 TRR, suspended it for a nominal period, to be effective

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[6] SCE made five stated rate TRR filings to recover its Base TRR for the period April 1, 1998 through December 31, 2011 in Dockets No. ER97-2355, ER02-925, ER06-186, ER08-1343, and ER09-1534. SCE refers to these filings as TO1 through TO5 (for "Transmission Owner Base TRR filing No. 1", etc.). Additionally, SCE also had a complementary formula mechanism to recover Commission-approved Construction Work In Progress ("CWIP") Base TRR costs from the period March 1, 2008 through December 31, 2011 (*see* Docket Nos. ER08-375 and EL07-62). The separate CWIP formula mechanism was terminated upon the establishment of the Original Formula Rate, since CWIP costs are included in the Formula Rate.

January 1, 2018, subject to refund, and established hearing and settlement judge procedures.[7] As of the date of this filing, parties in Docket No. ER18-169 remain in settlement proceedings.

SCE's Formula Rate consists of two components: (1) the Formula Rate Protocols ("Formula Protocols," Attachment 1 to Appendix IX of SCE's TO Tariff); and (2) the Formula Rate Spreadsheet ("Formula Spreadsheet," Attachment 2 to Appendix IX of SCE's TO Tariff). The Formula Protocols set forth process-related items, such as the Annual Update filing timeline, as well as various requirements that SCE must meet in Annual Update informational filings or while the Formula Rate is in effect. The Formula Spreadsheet is the set of calculations that SCE must follow in calculating its Base TRR.

Section 3 of the Formula Rate Protocols specifies that each year SCE will file an Annual Update on or before December 1, revising the Base TRR and associated rates to be effective on January 1 of the upcoming Rate Year. In accordance with Section 3, SCE filed its 2019 Annual Update ("TO2019 Annual Update") on November 29, 2018. That submission was an informational update and did not subject SCE's Formula Rate to modification. The Rate Year for TO2019 Annual Update is January 1, 2019 through December 31, 2019.

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[7] *Southern California Edison Co.*, 161 FERC 61,309.

II. PURPOSE OF FILING

As stated above, SCE's regulatory and financial conditions have changed dramatically since the submission of the Second Formula Rate and a new filing is necessary. In this filing, SCE describes the operational measures it is implementing to strengthen its system and mitigate the increasing risk of wildfires to its customers' safety, property and its employees. However, there are significant wildfire factors outside of SCE's control that create a persistent risk of a devastating wildfire.[8]

There has been a dramatic change in financial risk to California utilities caused by the State Courts' application of inverse condemnation combined with the CPUC's recent decision denying wildfire-associated cost recovery.[9] This confluence of factors combined with the increased risk of catastrophic wildfires, has driven one of the California utilities into bankruptcy and have put the other California utilities, including SCE, in danger of falling below investment grade. SCE is submitting revisions to its Formula Rate to account for this risk and ensure it can encourage investment sufficient to attract the capital necessary to provide safe and reliable electric service.

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8 Such risks include climate conditions, vegetation and forest management activities beyond what SCE performs surrounding its grid infrastructure, density of structures in close proximity or within the wildfire-urban interface within SCE's territory, fire agency resources and suppression response capabilities, along with fire ignitions caused by other sources. Mr. Brian Chen discusses these risks as well as the actions SCE is taking to mitigate wildfire ignition risk in Exhibit No. SCE-20.

9 CPUC Decision (D.)17-11-033, *Decision Denying Application* (issued December 6, 2017); reh'g denied, D.18-07-025 *Order Denying Rehearing of D.17-11-033* (July 12, 2018).

In this filing, SCE proposes a base ROE request that is founded on, and fully supported by, the Commission's established ROE policies. SCE thus applies the four financial models utilized in the Commission's October 2018 Order Directing Briefs ("NETO Briefing Order")[10]—which includes the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the historical Risk Premium model, and Expected Earnings—and determines the "conventional" ROE that is required to reflect the significant non-wildfire regulatory and legislative risks that SCE faces as a public electric utility operating in California.[11] SCE also analyzes how the additional risks it faces as a result of wildfires affect SCE's ability to attract capital. While these wildfire risks require additional analysis to complement the conventional application of the four financial models, this additional analysis is fully consistent with the Commission's rationale in the NETO Briefing Order because this analysis connects SCE's "particular circumstance[]" and its unique risks with the capital attraction standard that underlies the Commission's ROE policies.[12] SCE accordingly requests an increase to its base ROE to account for the asymmetric wildfire risk that cannot be estimated fully by standard

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[10] 165 FERC ¶ 61,030.

[11] Dr. Bente Villadsen provides testimony to support SCE's proposed base ROE, in Exhibit SCE-25. Dr. Villadsen's testimony includes application of the multiple-model methodology proposed by the Commission in the NETO Briefing Order, with certain refinements to the proposed methodology. Dr. Gary Stern provides testimony that outlines the unique and significant non-wildfire regulatory and legislative risks that SCE faces as a public electric utility operating in California, in Exhibit SCE-21.

[12] *See, e.g.*, NETO Briefing Order at PP 21, 24.

financial models. This ROE is described in Section IV below and summarized in the testimony of Mr. Daniel Wood, Exhibit No. SCE-19.

Besides changes to ROE, SCE is seeking certain limited revisions to the Second Formula Rate to improve the operation of the Formula Rate. These revisions are explained in Sections IV and V below and in the testimony of Mr. Jeff Nelson, Exhibit No. SCE-1. A full list of all proposed revisions to the Formula Rate is included in Exhibit Nos. SCE-5 (Formula Spreadsheet Revisions) and SCE-6 (Formula Protocol Revisions).

Under the proposed rates, SCE's proposed retail Base TRR for calendar year 2019 (effective June 12, 2019) will be $1,328,294,741. This compares to the current Base TRR of $ 1,038,486,906, as filed by SCE in 2018 in its TO2019 Annual Update.

Additionally, in this filing SCE is re-collating Attachment 1 to Appendix IX of SCE's TO Tariff and Attachment 2 to Appendix IX of SCE's TO Tariff. The re-collation is an administrative change and is being made to reassign new collation values to SCE's TO Tariff eTariff database. SCE is currently utilizing nearly the full range of the available collation values under the FERC XML schema. Because the tariff record collation value determines the position of the record in the tariff, SCE was severely limited in its ability to file additional tariff records to its eTariff database without inserting the new records in between existing records. The re-collation being performed in this filing will rearrange the position of the tariff record being submitted herein.

III. EFFECTIVE DATE

SCE requests that the Commission accept the proposed Formula Rate revisions set forth in this filing with an effective date of June 12, 2019 without suspension or hearing, which is 62 days after the date of this filing. If the Commission suspends the effective date for five months,[13] SCE requests an effective date for Formula Rate of November 12, 2019. However, in the event of a suspension, SCE requests that, while the Formula Rate will be in effect beginning November 12, 2019, for administrative and customer clarity considerations, the associated retail and wholesale transmission rates be updated on January 1, 2020.[14] January 1 aligns with SCE's normal rate update cycle and the requested delay will eliminate the need to update the rates twice within a period of less than two months. To the extent that waiver is required from the Commission's rules and regulations in order for SCE to implement this in the event that the Commission suspends SCE's filing for a period of five months, SCE respectfully requests waiver of any applicable rules or regulations.

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[13] 16 U.S.C. § 824d(d) (2018).

[14] The Formula Rate will true-up any potential mismatch between the approved Formula Rate and the wholesale and retail rates charged to customers from November 12, 2019 through December 31, 2019 as part of the normal 2019 True-up TRR process. Thus, customers will be properly charged for transmission even with the slightly delayed implementation.

IV. DESCRIPTION OF FILING

A. Return on Equity

The proposed Return on Equity ("ROE") in the Formula Rate reflects a base ROE of 17.12%.[15] This ROE was derived by applying the "conventional" ROE for utilities of like risks of SCE without a consideration of wildfires and by analyzing the impact of the significant wildfire risk that SCE faces on the ROE level that SCE requires to attract capital and satisfy investors' expectations for companies with corresponding risks.
The conventional ROE is 11.12% and is determined by applying the multiple-model methodology proposed by the Commission in the NETO Briefing Order, with certain refinements to the proposed methodology. The conventional ROE does not reflect the extraordinary wildfire risks faced by SCE, and SCE applies a 6.0% adjustment to ROE to account for the extraordinary wildfire risks.[16]

i. Conventional ROE

Dr. Villadsen's evaluation and recommendation concerning the conventional ROE for SCE is based on the Commission's most recent guidance and policy objectives,[17]

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[15] This value does not include the requested CAISO 0.5% incentive adder or SCE's specific project incentive adders.

[16] The conventional ROE is supported by the analysis and testimony of Dr. Bente Villadsen in Exhibit Nos. SCE-25. Mr. Frank Graves provides testimony and analysis on the unique wildfire risk in Exhibit Nos. SCE-22 and SCE-24. The testimony of Mr. Daniel Wood relies upon the testimony and analysis of Dr. Villadsen and Mr. Graves and concludes that a base ROE of 17.12% is just and reasonable and will allow SCE to attract capital on reasonable terms, at Exhibit SCE-19.

[17] *See* Exhibit No. SCE-25 at pp. 3-5.

including the multiple-model methodology proposed by the Commission in the NETO Briefing Order[18] and Opinion No. 531. Dr. Villadsen first assembled a proxy group of comparable electric utilities using the proxy group screening criteria set forth in the NETO Briefing Order. When establishing the proxy group, Dr. Villadsen did not apply the NETO Briefing Order criteria that screened a company because it was more than one notch above or below SCE's credit rating. She did this for two reasons: (1) such a restriction would lead to a sample that is too small to capture the electric utility industry; and (2) SCE's credit rating has been evolving over the past year and may continue to do so. For these reasons, Dr. Villadsen included all electric companies that are considered investment grade.

Dr. Villadsen then evaluated the cost of equity for SCE using the four financial models adopted in the NETO Briefing Order: the DCF model, the Capital Asset Pricing Model ("CAPM"), Expected Earnings, and Risk Premium. For CAPM, Dr. Villadsen applies a forecast yield, as opposed to the current yield, as a measure of the risk-free rate. She explains that she made this adjustment to the NETO Briefing Order's guidance because it will more accurately reflect the rates expected to be in effect during time

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[18] *Martha Coakley et al. v. Bangor Hydro-Electric Co. et al.*, Order Directing Briefs, 165 FERC ¶ 61,030 (2018) ("NETO Briefing Order"). In this order, the Commission proposed the new methodology and established a paper hearing on this proposed methodology to the issues in the relevant dockets. *Id.* at P 61. As of the date of this filing, the Commission has not issued a decision on the paper hearing. SCE simultaneously sought leave to be permitted to submit an Initial Brief and submitted an Initial Briefs to comment on specific policy questions of general applicability raised in the NETO Briefing Order.

period the ROE will be in effect. She then develops a composite Zone of Reasonableness produced by the DCF, CAPM and Expected Earnings models, applying the enhancements discussed above, and identifies the central tendency for average and above-average risk utilities based upon the NETO Briefing Order.

Dr. Villadsen then considers the substantial risks and uncertainties unique to California transmission investment, including the risks analyzed in the testimony of Dr. Gary Stern in Exhibit SCE-21. Such risks include California's aggressive environmental policy designed to dramatically reduce carbon emissions, California's evolving approach to energy procurement and electric retail competition and the increasing regulatory uncertainty caused by state regulatory lag.

Dr. Villadsen concludes SCE is an above-average risk utility in its proxy group and should receive a 11.12% conventional ROE. Dr. Villadsen indicates this conclusion is made without consideration for the substantial wildfire risk SCE faces because the financial models described above do not reflect the extraordinary wildfire risk faced by SCE.

ii. ROE Increase to Address Extraordinary Wildfire Risk

The analysis and testimony of Mr. Graves addresses the substantial wildfire risk SCE faces.[19] Mr. Graves concludes that the extreme potential liabilities, and apparently growing risk of megafires in California, plus the state's unsettled legal and regulatory

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[19] Exhibit SCE-22.

approach to assigning financial responsibilities of those events, create an environment that is not sustainable for utilities. Mr. Graves concludes that if left unaddressed, this environment will significantly impede a California utility's ability to fund ongoing normal business. Based upon extensive analysis, Mr. Graves concludes an ROE allowance of 600 basis points, is consistent with the apparent size of the problem as seen from either recent past fires or from pricing evidence for insurance and catastrophe bonds.

iii. Conventional ROE Methodologies Do Not Account for Extraordinary Wildfire Risk

In the context of the increase to ROE to address wildfire risk, Dr. Villadsen indicates that utilizing solely a conventional application of the Commission's construct for determining a Zone of Reasonableness is not sufficient to satisfy the capital attraction standard that is the foundation of that construct.[20] The impact of wildfire risk on SCE requires additional analysis of ROEs that are required to attract equity capital for companies (in other industries) that face risks as significant as the wildfire risk that SCE faces. As support for the reasonableness of SCE's request, Dr. Villadsen notes non-electric utilities with risks more comparable to those faced by SCE have ROEs significantly higher than SCE's requested 17.12%. Further, she also creates a Zone

[20] *See, e.g.*, NETO Briefing Order at P 21 (concluding, based on guidance from cases involving FPA Section 205, that a "company's risk profile" is the chief factor in determining whether an ROE is just and reasonable).

of Reasonableness based on a capital-intensive network industries proxy group. Compared to the traditional Commission utility proxy group, Dr. Villadsen's capital intensive network industries proxy group faces risk more comparable to those confronted by SCE. Based on this proxy group, she concludes SCE's Zone of Reasonableness extends to at least 18.2% and notes that, after excluding outliers, there are multiple results above 18.2%, reaching as high as 26.4%.

iv. Recommended ROE

The testimony of Mr. Wood concludes that authorizing a 600 basis point increase to ROE is necessary to provide investors with confidence that they have a reasonable opportunity to earn a return on their investment at a level that is commensurate with conventional ROE, which is 11.12%. The returns must be adjusted upwards based on a consideration of the wildfire-associated risks equity holders face. Mr. Wood and Mr. Graves each conclude that such an increase *does not* capture the true or full cost of the risks. But, increase is needed to compensate investors, albeit partially, for those risks. Therefore, looking at all of the evidence, Mr. Wood recommends a 17.12% base ROE, which includes a 6.0% consideration for wildfire risk, as a just and reasonable ROE for SCE that satisfies *Hope* and *Bluefield.*[21]

[21] *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944) (*Hope*); *Bluefield Water Works and Improvement Co. v. Public Service Commission of the State of West Virginia*, 262 U.S. 679 (1923) (*Bluefield*).

Additionally, pursuant to Commission policy, SCE's ROE request also includes (1) a requested 50 basis point ROE adder for SCE participation in a Commission-approved Independent System Operator, the California Independent System Operator[22] and (2) the specific project incentive adders that SCE has received for certain transmission projects.[23] Dr. Villadsen's testimony explains that the 50 basis point adder for ISO/RTO membership has been approved by the Commission,[24] and discusses the significant benefits that flow from membership in an ISO/RTO.[25] Further, Dr. Villadsen explains the specific transmission project adders that SCE has received for three of its transmission projects.[26]

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[22] The Commission initially approved this adder in Docket No. EL07-62-000. *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) at P 158. On December 29, 2017 in Docket ER18-169-000, the Commission issued an order accepting SCE's Second Formula Rate subject to refund and granted SCE's request for the CAISO Adder. *Southern California Edison Co.*, 161 FERC P 61,309 (2017). On February 28, 2018, the Commission issued an order granting a rehearing request concerning the grant of the CAISO Adder and that rehearing remains pending.

[23] The Commission has authorized the following transmission project adders: Rancho Vista, 0.75 percent; Tehachapi, 1.25 percent; and Devers-Colorado River, 1.00 percent. *See*, *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007) at P 129 and *Southern California Edison Co*., 132 FERC ¶ 61,213 (2010).

[24] Dr. Villadsen's testimony recognizes this adder is currently under review by the Commission, both on rehearing in Docket No. ER18-169 and on remand in Docket Nos. ER14-2529-005, *et al*. However, as of the date of this filing, SCE remains eligible for that adder based upon approval by this Commission.

[25] Dr. Stern also addresses the benefits that flow from SCE's participation in the CAISO. *See* Exhibit SCE-21, at pp. 34-36.

[26] Exhibit SCE-25, at p. 18.

B. Adjustment to Total Proprietary Capital and Non-Rate Base Debt

On February 28, 2019, SCE filed its 2018 10-K financial report reflecting accrual of a fourth quarter non-cash net charge of $1.8 billion against earnings due to potential damage claims and other costs associated with wildfire and mudslide events of 2017 and 2018 in SCE's service territory ("Wildfire Reserve"). SCE accrued this charge as required by accounting principles generally accepted in the United States of America ("GAAP"). GAAP requires that a contingent liability be recorded on an accrual basis when liability is probable and reasonably estimable, even though no actual liability has been incurred. As Mr. Sergio Deana explains in his testimony, SCE lacks sufficient information regarding cost recovery of wildfire-related liability at the CPUC to record an offsetting "regulatory asset" at this time. The impact of taking the Wildfire Reserve without sufficient offsets has been to lower SCE's equity ratio under the Second Formula Rate even though no equity has in fact been adjusted. This substantial non-cash net charge is due to the same unsettled legal and regulatory approach—*i.e.,* California's strict liability inverse condemnation in conjunction with the CPUC's application of prudency standards to megafire cost recovery—and negatively impacts investor expectations. To reflect a just and reasonable return on capital, Mr. Deana concludes that wildfire related non-cash net charges, including this Wildfire Reserve, should be excluded when determining SCE's total proprietary capital.

In addition, Mr. Deana describes the Formula Rate's exclusion of debt that is not used to finance rate base when calculating SCE's capital structure. This currently includes debt dedicated toward fuel purchases, and may in the future include debt dedicated to finance wildfire liability.

C. Overview of the Formula Rate

SCE's Base TRR is calculated by the Formula Rate according to the following basic formula:[27]

Base TRR = Prior Year TRR +
Incremental Forecast Period TRR ("IFPTRR") +
True Up Adjustment

Where:

- The Prior Year TRR represents SCE's costs of owning and operating SCE's CAISO-controlled transmission facilities, with rate base components being based on End-of-Year values for the Prior Year.[28]
- The Incremental Forecast Period TRR represents the incremental TRR costs that SCE is projected to incur during the Rate Year relative to

[27] Under certain conditions, as set forth Section 1 of the Formula Protocols, SCE may also include a "Cost Adjustment" as a fourth component of the Base TRR. The purpose of the Cost Adjustment provision is to allow an adjustment to the Base TRR to reflect known unusual one-time changes to costs. Mr. Hansen fully explains the Cost Adjustment feature of the Formula Rate in his testimony, Exhibit No. SCE-3. Although permitted, SCE has not had a need to include a Cost Adjustment in any of its Annual Update filings under the Original Formula Rate.

[28] The "Prior Year" is the calendar year previous to the year that the Annual Update is submitted. The Annual Update sets the Base TRR for the "Rate Year," which is the calendar year following the year the Annual Update is submitted. There is thus a two-year difference between the Prior Year and the Rate Year.

those already included in the Prior Year through the Prior Year TRR component.

- The True Up Adjustment component of the Base TRR reflects the difference between SCE's actual costs of owning and operating its CAISO-transmission assets during the Prior Year, and the actual retail transmission revenues that SCE received during the Prior Year. It is included as a component of the Base TRR to ensure that SCE recovers its actual costs of owning and operating its transmission system over time. To determine the True Up Adjustment, SCE's Formula Rate calculates a "True Up TRR," which is the measure of SCE's actual Base TRR costs incurred during the Prior Year.

D. The Annual Update Process

The Annual Update process is set forth in the Section 3 of the Formula Protocols, and includes the following aspects:

1) On or before June 15 of each year, SCE will post on its website a "Draft Annual Update" which will include substantially all aspects of the Annual Update informational filing (Section 3.a of the Formula Rate Protocols).
2) On or before July 15 of each year, a Draft Annual Update conference is to be held, the purpose of which is for SCE to meet with customers to

discuss the Draft Annual Update (Section 3.b of Formula Rate Protocols).

3) Between the period from June 15 to November 1, customers may submit data requests to SCE, and SCE shall make a good faith effort to respond to information requests in writing within ten business days (Section 3.c of Formula Rate Protocols).

4) On or before December 1 of each year, SCE will submit the Annual Update informational filing (Section 3.d of Formula Rate Protocols).

5) On January 1 of the following year, the Base TRR and associated retail and wholesale transmission rates included in the Annual Update filing will be placed into effect (Section 3.d of Formula Rate Protocols).

SCE is not proposing any revisions to the Annual Update process relative to the process that is currently in effect.

E. Allocation of Costs Between CAISO and Non-CAISO

Not all of the costs that SCE books as Transmission in its accounting system and reports to the Commission in its annual FERC Form No. 1 filings are Commission-jurisdictional. A significant portion of SCE's plant booked as Transmission plant, or costs booked as Transmission Operations and Maintenance ("O&M") costs, represent costs that are under the CPUC jurisdiction. Accordingly, SCE must determine for ratemaking purposes the portion of Transmission plant and Transmission O&M costs that are Commission-jurisdictional.

To determine the portion of plant booked for accounting purposes as Transmission Plant that is under the CAISO's Operational Control and therefore is Commission-jurisdictional ("ISO Transmission Plant"), SCE performs an annual Transmission Plant Study. The Transmission Plant Study examines all facilities that are booked as Transmission Plant and determines what portion of the facilities are ISO Transmission Plant. Mr. Jacob Moon fully supports and explains the Transmission Plant Study in his testimony, Exhibit No. SCE-9.

SCE's Formula Rate also includes a mechanism to determine the portion of total Transmission O&M expense that is related to the ISO Transmission Plant and will be recovered through the Formula Rate. Mr. Daniel Allstun supports and explains the overall Transmission O&M Expense determination in his testimony, Exhibit No. SCE-10.

F. Implementation of Changes

The Second Formula Rate includes a provision for a "Final True Up Adjustment,"[29] which states that SCE is entitled and required to recover any costs through the term of the Formula Rate. Accordingly, although SCE is proposing an effective date of June 12, 2019 for the proposed changes to the Formula Rate, the Original Formula Rate will still be utilized for the purpose of calculating the True Up

[29] *See* Section 4 of the Original Formula Rate 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."

TRR for the 2017 year and the Second Formula Rate will still be utilized for the purpose of calculating the True Up TRR for the 2018 year.

In addition, SCE is proposing provisions that will ensure that the True Up TRRs for the portion of time the Second Formula Rate was in effect in 2019 are calculated pursuant to the Second Formula Rate. Specifically, revised Section 6 of the Formula Rate protocols ("Transition of the Original Formula Rate to the Formula Rate") explains that "any transition from one formula rate to its successor formula rate shall ensure that the True Up TRRs for any years for which a previous formula rate or formula rates were in effect during all or part of that year are calculated utilizing the formula rate, or formula rates, that were in effect during the year being trued up." This requirement is implemented in the calculation of the True Up Adjustment component of the proposed 2019 Base TRR for the Formula Rate. The testimony of Mr. Hansen explains the implementation of this transition provision testimony, Exhibit No. SCE-3.

G. Depreciation Rates

SCE is not making any changes to the depreciation rates used in the Second Formula Rate associated with ISO Transmission plant, in order to remain in alignment with the rates that SCE has proposed in its recent CPUC 2018 General Rate Case ("GRC"). The depreciation rates are supported by the testimony of Mr. David Gunn in Exhibit Nos. SCE-7 and SCE-8.

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H. Tax Cuts and Jobs Act and ADIT Methodology

On January 4, 2019, the Commission issued the Order Accepting Tariff Revisions, Subject to Condition in response to a request by SCE to revise its Transmission Owner Tariff as a result of Public Law 115-97, commonly referred to as the Tax Cuts and Jobs Act ("TCJA").[30] This order, effective November 16, 2018, approved changes to SCE's Second Formula Rate to reflect the tax-related ratemaking implications resulting from the TCJA. SCE maintains these recent changes that were adopted into its Second Formula Rate.

In addition, SCE submitted proposed revisions on January 22, 2019 to eliminate the use of two-step averaging methodology in the calculation of Accumulated Deferred Income Tax ("ADIT") balances in SCE's currently-effective Second Formula Rate, with a proposed effective date of January 1, 2019.[31] SCE now uses the pro rata method for averaging ADIT in the Income Tax Formula of the Second Formula Rate. SCE maintains this ADIT methodology change as adopted into its Second Formula Rate.

Mr. Lopez provides detailed discussion concerning these issues in his testimony, Exhibit No. SCE-11.

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[30] *S. Cal. Edison Co.*, 166 FERC ¶ 61,006 (2019).

[31] This submission was made pursuant to the Commission's Order on Paper Hearing, issued on December 20, 2018. *S. Cal. Edison Co.*, 165 FERC ¶ 61,241 (2018).

V. ADDITIONAL PROPOSED REFINEMENTS TO THE FORMULA RATE

Since filing its Second Formula Rate in late 2017, SCE has identified certain refinements that have the potential to benefit all parties, provide for a more efficient process, ensure compliance with evolving rules, and improve the treatment of certain costs. With that in mind, below is a short discussion of the key changes to the Second Formula Rate that are included in this filing. There are many less significant revisions that SCE is proposing to make to the Formula Rate. Exhibit Nos. SCE-5 and SCE-6, supported by Mr. Hansen, present a listing of all proposed revisions to the Formula Spreadsheet and Formula Protocols, and the witness supporting each.

A. Proposed Refinements to the Formula Rate

1. Adjustment to Gross Load for purposes Calculation of Wholesale Rates

To determine wholesale rates, SCE's Schedule 30 of the Formula Rate Spreadsheet 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. To ensure that SCE's Pump Load component of Gross Load will over time equal actual pump load, SCE is proposing to include a new mechanism: the addition of a new Line 3 Schedule 32 "Pump Load True Up," and a new Note 4 that defines the Pump Load True Up component. The new component is then added to the sum of SCE retail sales and the Pump Load forecast, ensuring that over time the amount of pump load equals actual MWh of Pump Load. Mr. Hansen discusses this in his testimony, Exhibit SCE-3.

2. Refinements to Schedule 17

To clarify the separate purposes of Schedule 17 and Schedule 18 of the Formula Rate Spreadsheet, SCE proposes to change Line 15 of Schedule 17 to remove reference to Schedule 18. SCE also proposes the following change to Instruction 1 of Schedule 17:

Instruction 1:

> ~~*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.*~~
>
> <u>**1) Depreciation rates on lines 17a-17m are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet in effect during the Prior Year.**</u>

Mr. Gunn discusses this change in his testimony, Exhibit SCE-7.

3. Use of FERC Form 1 to the Extent Possible

SCE is proposing revisions, primarily to Schedule 5 ROR-3, to improve the calculation of the cost of debt so that it is more fully based on cost information included in FERC Form 1. Mr. Deana discusses these revisions in his testimony, Exhibit SCE-17.

B. Revisions to the Formula Rate Protocols

1. Adjustment to Definition of Material Accounting Changes

SCE proposes changes to the definition of "Material Accounting Changes," in footnote 4, to clarify the scope of information that must be included in each Draft Annual

Update. Specifically, "Material Accounting Changes" is proposed to be revised as follows:

> any material change **that affects SCE's transmission rates as follows:** ~~in SCE's~~ (i) accounting policies and practices from those in effect for the Prior Year upon which the immediately preceding Annual Update was based**, including those resulting from any new or revised accounting guidance from the Financial Accounting Standards Board;**~~,~~ or (ii) internal corporate cost allocation policies or practices **in effect for the Prior Year** ~~from those policies and/or practices in effect for the Prior Year~~ upon which the immediately preceding Annual Update was based**; or (iii) income tax elections from those in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iv) cost allocation policies between EIX, SCE, and subsidiaries of either, from those in effect for the Prior Year upon which the immediately preceding Annual Update was based. Additionally, a Material Accounting Change shall also include any: (i) initial implementation of an accounting standard; or (ii) initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting.**

These clarifications and additions will provide greater transparency and predictability for stakeholders when they review the Draft Annual Update.

VI. CONTENTS OF THIS FILING

The documents submitted with this filing consist of this letter of transmittal and the following documents:

1. A revised clean version of SCE's TO Tariff sheets reflecting the proposed revisions to the Formula Rate;
2. A red-lined version of the revised TO Tariff sheets reflecting the proposed revisions to the Formula Rate;
3. The relevant Cost of Service Statements;
4. Attestation by Aaron Moss, Vice President;

5. Prepared Direct Testimony, Exhibits, and Workpapers of the following witnesses:
    a. Exhibits SCE-1 and SCE-2: Testimony of Mr. Jeffrey L. Nelson and exhibits thereto;
    b. Exhibits SCE-3 through SCE-6: Testimony of Mr. Berton J. Hansen and exhibits thereto;
    c. Exhibits SCE-7 through SCE-8: Testimony of Mr. David Gunn and exhibits thereto;
    d. Exhibit SCE-9: Testimony of Mr. Jacob Moon;
    e. Exhibit SCE-10: Testimony of Mr. Daniel J. Allstun;
    f. Exhibit SCE-11: Testimony of Mr. Alfred Lopez;
    g. Exhibit SCE-12: Testimony of Mr. Robert G. Mindess;
    h. Exhibits SCE-13 through SCE-14: Testimony of Ms. Jee Kim and exhibits thereto;
    i. Exhibit SCE-15: Testimony of Mr. Antonio Ocegueda;
    j. Exhibit SCE-16: Testimony of Mr. Robert A. Thomas;
    k. Exhibit SCE-17 and SCE-18: Testimony of Mr. Sergio Deana;
    l. Exhibit SCE-19: Testimony of Mr. Daniel Wood;
    m. Exhibit SCE-20: Testimony of Dr. Brian Chen;
    n. Exhibit SCE-21: Testimony of Dr. Gary Stern;
    o. Exhibits SCE-22 through SCE-24: Testimony of Mr. Frank Graves;
    p. Exhibits SCE-25 through SCE-28: Testimony of Dr. Bente Villadsen and exhibits thereto;
    q. Exhibit SCE-29: Workpapers supporting all witnesses

VII. COMMUNICATIONS

SCE requests that all correspondence, pleadings and other communications concerning this filing be served upon:

Rebecca Furman
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VIII. REQUEST FOR WAIVERS

To the extent that waivers of the Commission's cost support regulations, in 18 C.F.R. § 35.13 (2010), are necessary,[33] SCE respectfully requests such waivers, including waiver of the full Period I and Period II data requirements. Good cause exists for such waiver. The statements, testimony and exhibits accompanying this filing, together with SCE's publicly-available FERC Form 1 information, provide ample support for the reasonableness of the proposed revisions to the formula rates. Detailed statements of the applicant's cost of service are not needed where the proposed rates are formulary and will be based on actual costs as reflected in the applicant's audited books and records. Further, such waiver would be consistent with Commission precedent in SCE's Original Formula Rate and other formula rates of this nature.[34]

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[32] SCE requests waiver of Section 385.203(b)(3) of the Commission's Regulations to allow three people to be on this list.

[33] 18 C.F.R. § 35.13.

[34] *Southern California Edison Co.*, 136 FERC ¶ 61,074 at P 29 (2011)*(* granting waiver of request for waiver of the requirements under section 35.13 regarding the filing of a full Period I and Period II study); *Pub. Serv. Elec. and Gas Co.*, 124 FERC ¶ 61,303 at PP 23-24

IX. OTHER FILING REQUIREMENTS

No expenses or costs included in the cost of service statements tendered herein have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative or unnecessary costs that are demonstrably the product of discriminatory employment practices.

This filing conforms to any rule of general applicability and to any Commission order specifically applicable to SCE, and has made copies of this letter and all enclosures available for public inspection in SCE's principal office located in Rosemead, California. SCE has e-mailed a link to this filing to those persons who are on the service lists for Docket No. ER18-169.

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(2008) (granting waiver of Sections 35.13(d)(1)-(2), 35.13(d)(5), and 35.13(h)); *Okla. Gas & Elec. Co.*, 122 FERC ¶ 61,071 at P 41 (2008) (same); *Am. Elec. Power Serv. Corp.*, 120 FERC ¶ 61,205 at P 41 (2007) (granting waiver of Period I and II data); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238 at PP 92-94 (2007) (granting waiver of Period I and II data and cost-of-service statements); *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219 at P 57 (2007) (same); *Duquesne Light Co.*, 118 FERC ¶ 61,087 at P 79 (2007) (granting waiver of Sections 35.13(d)(1)-(2) and 35.13(h)); *Idaho Power Co.*, 115 FERC ¶ 61,281 at P 20 (2006) (granting waiver of Period II data); *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308 at PP 55-56 (2005) (granting waiver of Period I and II data).

Respectfully submitted,

*/s/ Matthew Dwyer*____________
Matthew Dwyer

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Dated: April 11, 2019

COST OF SERVICE

STATEMENTS

Statement BG - Period II
Retail

Southern California Edison Company
Retail Revenues at Proposed Rates

Revenues ($)

Rate Group	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
Domestic	$49,167,632	$38,315,701	$40,478,754	$40,703,401	$41,730,488	$41,283,424
TOU-GS-1	$8,663,255	$7,622,970	$8,008,929	$8,283,345	$8,446,416	$8,207,635
TC-1	$61,384	$48,160	$59,131	$52,146	$53,436	$51,924
TOU-GS-2	$18,040,031	$14,487,709	$16,125,973	$17,957,569	$19,029,700	$17,853,087
TOU-GS-3	$9,521,057	$8,308,763	$9,214,766	$9,918,369	$10,850,310	$9,654,455
TOU-8-Sec	$9,342,897	$8,169,641	$8,975,167	$9,377,026	$9,837,658	$9,348,395
TOU-8-Pri	$5,877,033	$5,031,468	$5,480,331	$5,709,121	$6,108,190	$5,654,647
TOU-8-Sub	$5,664,371	$5,059,785	$5,320,700	$5,377,741	$5,765,445	$5,445,257
TOU-8-Standby-SEC	$237,593	$240,639	$248,466	$253,104	$253,886	$259,322
TOU-8-Standby-PRI	$739,600	$762,478	$780,154	$795,620	$841,095	$855,743
TOU-8-Standby-SUB	$1,773,076	$1,837,918	$1,813,058	$1,856,388	$1,930,709	$2,083,803
TOU-PA-2	$1,667,282	$1,239,050	$1,339,957	$1,752,859	$1,868,898	$1,860,912
TOU-PA-3	$1,232,954	$1,081,685	$1,159,885	$1,290,805	$1,373,824	$1,334,791
Street Lighting	$506,590	$469,414	$486,520	$477,687	$473,049	$449,706
Total	$112,494,756	$92,675,381	$99,491,789	$103,805,183	$108,563,105	$104,343,100

Rate Group	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Period II Total
Domestic	$55,880,995	$58,514,297	$54,698,226	$50,062,264	$37,991,664	$45,281,350	$554,108,197
TOU-GS-1	$9,601,130	$9,734,055	$9,189,009	$9,241,950	$7,818,626	$8,421,695	$103,239,014
TC-1	$52,512	$55,363	$48,508	$56,316	$50,621	$58,994	$648,496
TOU-GS-2	$20,853,476	$21,592,000	$19,418,734	$20,535,540	$15,986,833	$17,451,367	$219,332,017
TOU-GS-3	$11,112,270	$11,341,357	$10,809,010	$11,468,782	$9,141,949	$9,679,227	$121,020,316
TOU-8-Sec	$10,208,107	$10,862,667	$9,969,169	$10,532,158	$8,922,817	$9,347,778	$114,893,480
TOU-8-Pri	$6,259,328	$6,603,560	$5,934,161	$6,471,444	$5,465,171	$5,703,672	$70,298,127
TOU-8-Sub	$5,601,992	$6,128,860	$5,142,835	$5,720,909	$5,203,227	$5,272,371	$65,703,494
TOU-8-Standby-SEC	$261,274	$277,996	$276,038	$267,044	$250,585	$241,727	$3,067,674
TOU-8-Standby-PRI	$870,501	$902,258	$928,940	$856,077	$794,299	$755,403	$9,882,169
TOU-8-Standby-SUB	$2,113,110	$2,069,329	$2,094,483	$2,163,765	$2,069,193	$1,989,794	$23,794,626
TOU-PA-2	$1,968,601	$2,068,439	$1,836,621	$1,968,652	$1,553,788	$1,720,940	$20,845,998
TOU-PA-3	$1,460,322	$1,526,884	$1,400,889	$1,456,382	$1,184,908	$1,241,608	$15,744,938
Street Lighting	$463,505	$456,759	$460,497	$485,247	$477,756	$507,250	$5,713,981
Total	$126,707,124	$132,133,824	$122,207,122	$121,286,531	$96,911,436	$107,673,176	$1,328,292,528

Notes:

1) Period II is January 2019 through December 2019.

Revenues are based on retail rates calculated in Schedule 33 of Formula Rate Spreadsheet.

Statement BG - Period II
Billing Determinants

Rate Group	Jan 2019			Feb 2019			Mar 2019			Apr 2019			May 2019			Jun 2019		
	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**
Domestic	2,397		0	1,868		0	1,973		0	1,984		0	2,034		0	2,012		0
TOU-GS-1	495		0	436		0	458		0	473		0	483		0	469		0
TC-1	5		0	4		0	5		0	5		0	5		0	5		0
TOU-GS-2		3,693	3		2,965	3		3,301	3		3,676	3		3,895	3		3,654	3
TOU-GS-3		1,784	6		1,556	6		1,727	6		1,859	6		2,034	6		1,809	6
TOU-8-Sec		1,670	0		1,460	0		1,604	0		1,676	0		1,758	0		1,671	0
TOU-8-Pri		1,071	0		917	0		999	0		1,041	0		1,114	0		1,031	0
TOU-8-Sub		1,025	0		916	0		963	0		973	0		1,044	0		986	0
TOU-8-Standby-SEC		24	24		24	24		26	24		27	24		27	24		28	24
TOU-8-Standby-PRI		94	114		98	114		101	114		104	114		112	114		115	114
TOU-8-Standby-SUB		238	699		249	699		245	699		253	699		266	699		294	699
TOU-PA-2		650	0		483	0		522	0		683	0		728	0		725	0
TOU-PA-3		386	1		339	1		363	1		404	1		430	1		418	1
Street Lighting	62	0	0	57	0	0	59	0	0	58	0	0	58	0	0	55	0	0
Total:	2,959	10,635	847	2,365	9,008	847	2,496	9,851	847	2,521	10,696	847	2,579	11,409	847	2,541	10,731	847

Rate Group	Jul 2019			Aug 2019			Sep 2019			Oct 2019			Nov 2019			Dec 2019			Total		
	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**	GWh	MW*	MW**
Domestic	2,724		0	2,852		0	2,666		0	2,440		0	1,852		0	2,207		0	27,012	0	0
TOU-GS-1	549		0	556		0	525		0	528		0	447		0	481		0	5,900	0	0
TC-1	5		0	5		0	4		0	5		0	5		0	5		0	58	0	0
TOU-GS-2		4,269	3		4,420	3		3,975	3		4,204	3		3,272	3		3,572	3	0	44,897	36
TOU-GS-3		2,083	6		2,126	6		2,026	6		2,150	6		1,713	6		1,814	6	0	22,683	70
TOU-8-Sec		1,824	0		1,941	0		1,781	0		1,882	0		1,594	0		1,670	0	0	20,531	0
TOU-8-Pri		1,141	0		1,204	0		1,082	0		1,180	0		996	0		1,040	0	0	12,817	0
TOU-8-Sub		1,014	0		1,109	0		931	0		1,036	0		942	0		954	0	0	11,894	0
TOU-8-Standby-SEC		28	24		31	24		31	24		29	24		26	24		25	24	0	325	285
TOU-8-Standby-PRI		118	114		124	114		128	114		115	114		104	114		97	114	0	1,310	1,373
TOU-8-Standby-SUB		299	699		291	699		296	699		308	699		291	699		277	699	0	3,309	8,394
TOU-PA-2		767	0		806	0		716	0		767	0		605	0		670	0	0	8,121	1
TOU-PA-3		458	1		479	1		439	1		456	1		371	1		389	1	0	4,933	8
Street Lighting	57	0	0	56	0	0	56	0	0	59	0	0	58	0	0	62	0	0	698	0	0
Total:	3,334	12,001	847	3,469	12,532	847	3,252	11,405	847	3,033	12,128	847	2,362	9,916	847	2,756	10,509	847	33,667	130,819	10,166

* Supplemental MW Demand
** Standby MW Demand

Statement BG - Period II
Wholesale

Southern California Edison Company
Existing Transmission Contract
Revenues at Proposed Rates

ETCs with rates that are presently based on SCE's TRR through the determination of the HVECAC rate:

Customer	FERC Rate Sch.	Billing Determinants (MW)	Proposed Rate	Revised Revenue
City of Azusa	373	4.000	$7.39	$354,720
City of Banning	379	3.000	$7.39	$266,040
City of Colton	362	3.000	$7.39	$266,040
LADWP	219	368.000	$7.39	$32,634,240
City of Riverside	390	30.000	$7.39	$2,660,400
City of Riverside	391	156.000	$7.39	$13,834,080
City of Riverside	392	12.000	$7.39	$1,064,160
City of Vernon	207	26.000	$7.39	$2,305,680
City of Vernon	360	11.000	$7.39	$975,480
		Total:		$54,360,840

Notes:

1) Period II is January 2019 through December 2019.

2) The Proposed Rate is the proposed High Voltage Existing Contracts Access Charge ("HVECAC") rate applicable to each ETC.
See Exhibit No. SCE-4 (Formula Rate Spreadsheet), Schedule 30, Line 9.

Statement BH - Period II
Retail

Southern California Edison Company
Retail Revenues at Current Rates

Revenues ($)

Rate Group	Jan 2019	Feb 2019	Mar 2019	Apr 2019	May 2019	Jun 2019
Domestic	$38,444,885	$29,959,603	$31,650,925	$31,826,580	$32,629,674	$32,280,109
TOU-GS-1	$6,772,612	$5,959,356	$6,261,084	$6,475,613	$6,603,095	$6,416,425
TC-1	$47,970	$37,636	$46,210	$40,751	$41,759	$40,577
TOU-GS-2	$14,116,563	$11,336,821	$12,618,785	$14,052,035	$14,890,993	$13,970,277
TOU-GS-3	$7,442,536	$6,494,895	$7,203,111	$7,753,113	$8,481,604	$7,546,813
TOU-8-Sec	$7,312,665	$6,394,360	$7,024,843	$7,339,378	$7,699,914	$7,316,968
TOU-8-Pri	$4,596,661	$3,935,311	$4,286,385	$4,465,330	$4,777,458	$4,422,724
TOU-8-Sub	$4,429,633	$3,956,837	$4,160,876	$4,205,484	$4,508,675	$4,258,283
TOU-8-Standby-SEC	$185,843	$188,228	$194,354	$197,984	$198,596	$202,850
TOU-8-Standby-PRI	$578,793	$596,687	$610,512	$622,609	$658,177	$669,633
TOU-8-Standby-SUB	$1,383,813	$1,434,520	$1,415,079	$1,448,965	$1,507,085	$1,626,807
TOU-PA-2	$1,305,670	$970,316	$1,049,337	$1,372,686	$1,463,557	$1,457,303
TOU-PA-3	$963,549	$845,333	$906,446	$1,008,759	$1,073,639	$1,043,134
Street Lighting	$396,077	$367,011	$380,385	$373,479	$369,853	$351,602
Total	$87,977,272	$72,476,913	$77,808,333	$81,182,765	$84,904,078	$81,603,505

Rate Group	Jul 2019	Aug 2019	Sep 2019	Oct 2019	Nov 2019	Dec 2019	Period II Total
Domestic	$43,694,161	$45,753,178	$42,769,337	$39,144,411	$29,706,233	$35,406,145	$433,265,243
TOU-GS-1	$7,505,809	$7,609,724	$7,183,627	$7,225,015	$6,112,312	$6,583,770	$80,708,442
TC-1	$41,037	$43,264	$37,908	$44,010	$39,559	$46,103	$506,782
TOU-GS-2	$16,318,122	$16,896,028	$15,195,417	$16,069,333	$12,509,907	$13,655,925	$171,630,206
TOU-GS-3	$8,686,376	$8,865,452	$8,449,319	$8,965,058	$7,146,191	$7,566,177	$94,600,645
TOU-8-Sec	$7,989,863	$8,502,186	$7,802,847	$8,243,497	$6,983,869	$7,316,486	$89,926,875
TOU-8-Pri	$4,895,669	$5,164,907	$4,641,343	$5,061,574	$4,274,527	$4,461,069	$54,982,958
TOU-8-Sub	$4,380,852	$4,792,871	$4,021,783	$4,473,847	$4,069,011	$4,123,083	$51,381,233
TOU-8-Standby-SEC	$204,378	$217,467	$215,934	$208,895	$196,012	$189,079	$2,399,618
TOU-8-Standby-PRI	$681,176	$706,014	$726,884	$669,894	$621,576	$591,153	$7,733,108
TOU-8-Standby-SUB	$1,649,725	$1,615,488	$1,635,159	$1,689,338	$1,615,381	$1,553,290	$18,574,652
TOU-PA-2	$1,541,636	$1,619,821	$1,438,281	$1,541,676	$1,216,791	$1,347,690	$16,324,763
TOU-PA-3	$1,141,237	$1,193,255	$1,094,790	$1,138,158	$926,002	$970,313	$12,304,613
Street Lighting	$362,391	$357,117	$360,040	$379,390	$373,533	$396,593	$4,467,473
Total	$99,092,432	$103,336,771	$95,572,669	$94,854,095	$75,790,904	$84,206,872	$1,038,806,610

Notes:

1) Period II is January 2019 through December 2019.

Statement BH - Period II
Wholesale

Southern California Edison Company
Existing Transmission Contract
Revenues at Current Rates

ETCs with rates that are presently based on SCE's TRR through the HVECAC rate:

Customer	FERC Rate Sch.	Billing Determinants (MW)	Current Rate	Current Revenue
City of Azusa	373	4.000	$5.68	$272,640
City of Banning	379	3.000	$5.68	$204,480
City of Colton	362	3.000	$5.68	$204,480
LADWP	219	368.000	$5.68	$25,082,880
City of Riverside	390	30.000	$5.68	$2,044,800
City of Riverside	391	156.000	$5.68	$10,632,960
City of Riverside	392	12.000	$5.68	$817,920
City of Vernon	207	26.000	$5.68	$1,772,160
City of Vernon	360	11.000	$5.68	$749,760
		Total:		$41,782,080

Notes:

1) Period II is January 2019 through December 2019.

2) The Current Rate is the High Voltage Existing Contracts Access Charge ("HVECAC") rate applicable to each ETC in 2019:

HVECAC: $5.68 Per kW per Month

See SCE November 29, 2018 Formula Rate Annual Update filing in ER18-169, Schedule 30, Line 12 of Formula Rate Spreadsheet.

Statement BL -- Period II
Southern California Edison Company
Proposed Transmission Rates effective June 12, 2019

Retail Base Transmission Rates*:

	Regular Service			Standby Service		Transportation Electrification Charge
CPUC Rate Group	$/kWh	$/kW	$/HP	$/kW	$/HP	$/kWh
Total Residential	$0.02051					
(Domestic)						
LSMP						
TOU-GS-1	$0.01750	$3.57		$3.57		$0.01750
TC-1	$0.01125					
TOU-GS-2		$4.88		$4.39		$0.01633
TOU-GS-3		$5.32		$4.39		$0.01633
Large Power						
TOU-8-Sec		$5.60				
TOU-8-Pri		$5.48				
TOU-8-Sub		$5.52				
TOU-8-Standby-Sec		$5.60		$4.39		$0.01433
TOU-8-Standby-Pri		$5.48		$1.97		$0.01282
TOU-8-Standby-Sub		$5.52		$0.66		$0.01120
Ag. & Pumping						
TOU-PA-2		$2.57	$1.91	$2.57	$1.91	
TOU-PA-3		$3.19		$3.19		
Street Lighting	$0.00819					

Wholesale Transmission Rates*:

Wholesale Rate	**Charge**	
High Voltage Existing Contracts Access Charge	$7.39	per kW
High Voltage Utility Specific Rate	$0.0138426	per kWh
Low Voltage Access Charge	$0.00045	per kWh

*Retail Base Transmission Rates are as set forth in Schedule 33 of the Formula Rate Spreadsheet. Wholesale Transmission Rates are as set forth in Schedule 30 of the Formula Rate Spreadsheet.

Statement BM

Southern California Edison Company

Construction Program Statement

Statement BM is a summary of data and supporting assumptions relating to the economics of any construction program to replace or expand the utility's power supply that shall be filed if the utility is filing for construction work in progress in rate base under § 35.25(c)(3) of this chapter. The filing utility shall describe generally its program for providing reliable and economic power for the period beginning with the date of the filing and ending with the tenth year after the test period. The statement shall include an assessment of the relative costs of adopting alternative strategies including an analysis of alternative production plant, *e.g.*, cogeneration, small power production, heightened load management and conservation efforts, additions to transmission plant or increased purchases of power, and an explanation of why the program adopted is prudent and consistent with a least-cost energy supply program.

Southern California Edison Company ("SCE") is currently authorized to recover through rates the Construction Work in Progress ("CWIP") expenditures related to eight transmission projects –the Tehachapi Renewable Transmission Project ("Tehachapi"), Calcite Substation Project (formerly Jasper; part of South of Kramer Transmission Project) ("Calcite"), West of Devers Transmission Project ("West of Devers"), Whirlwind Substation Expansion Project ("Whirlwind Expansion"), Colorado River Substation Expansion Project ("CRS Expansion"), Mesa Substation ("Mesa"), Alberhill System ("Alberhill"), and Eldorado-Lugo-Mohave Upgrade ("ELM") (collectively, "Projects"). Authorization to recover 100% of prudently-incurred CWIP associated with the Projects was granted by the Federal Energy Regulatory Commission ("FERC" or "Commission") in Docket Nos. EL07-62 in November 2007, EL10-81 in October 2010, EL11-10 in March 2011, and EL17-63 in October 2017.[1]

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[1] *Southern California Edison Co.*, 121 FERC ¶ 61,168 (2007); *Southern California Edison Co.*, 133 FERC ¶ 61,108 (2010); *Southern California Edison Co.*, 133 FERC ¶ 61,107 (2010); *Southern California Edison Co.*, 134 FERC ¶ 61,181 (2011); and *Southern California Edison Co.*, 161 FERC ¶ 61,107 (2017).

Currently, and over the next several years, SCE is engaging in a transmission infrastructure expansion in order to enlarge, improve, and reinforce the California Independent System Operator Corporation's ("CAISO") grid to maintain reliable service to customers and provide increased access to renewable generation sources. These projects will significantly improve the reliability of the CAISO bulk power transmission system and reduce the cost of power by reducing transmission congestion on the CAISO-controlled transmission grid. The Projects will also help SCE and other California utilities to meet the goals of the State of California's Renewable Portfolio Standards ("RPS").

In order to develop the Tehachapi and West of Devers projects, SCE worked closely with the CAISO, the California Public Utilities Commission ("CPUC"), and other stakeholders to determine whether these three projects would provide reliable renewable power to California. Alternatives for each project were considered and the projects were approved by both the CAISO and the CPUC Certificates of Public Convenience and Necessity ("CPCN") process. The CPCN process is extremely thorough and requires both the applicant and the CPUC to consider alternatives to each of the proposed Projects. The CPCN process evaluates a number of factors including, but not limited to, impacts on the transmission grid and other transmission users, cost-effectiveness, reasonable and prudent costs, alternative routes and configurations, non-wires alternatives, and impacts on the environment. The CPUC deemed that Tehachapi and West of Devers are preferable to all considered alternatives and approved the projects.

The Calcite, West of Devers, Whirlwind Expansion, and CRS Expansion projects ("Interconnection Projects") were developed primarily to allow for interconnection and delivery of renewable generation projects. The need for the Interconnection Projects was identified in the interconnection studies sponsored by the CAISO in connection with the CAISO's interconnection planning process and the development of the Large Generator Interconnection Agreements ("LGIAs"), which are approved and executed by the CAISO.

Alberhill, Mesa, and ELM projects were developed primarily to maintain electric reliability in Southern California. Alberhill was approved through CAISO's 2009 transmission planning process ("TPP") as a reliability project needed to serve current and projected demand for electricity and to main electric reliability in regions to the southeast of Alberhill 500/115 kV Substation and south of existing Valley 500/115 kV Substation in Riverside County. Mesa and ELM projects were both approved in CAISO's 2013-2014 TPP. While Mesa was approved as a reliability project to address the permanent retirement of the San Onofre Nuclear Generating Station ("SONGS") and the scheduled Once-Through Cooling ("OTC") generation shutdowns, expected by December 31, 2020, ELM was approved as a policy-driven project to increase power flow through existing transmission lines from Nevada to Southern California, and to relieve multiple area deliverability constraints.

All of the Projects will be placed under the CAISO's Operational Control once each Project is placed in-service. SCE has described below the process by which each of the Projects was developed including the consideration of alternatives. Additional details of the Projects can be found in SCE's petitions in Docket Nos. EL07-62, EL10-81, EL11-10, and EL17-63.

Tehachapi

The CAISO studied the Tehachapi Transmission Project as part of its CAISO South Regional Transmission Plan for 2006 ("CSRTP-2006") and developed a least-cost solution for the network component of the transmission infrastructure that will interconnect planned transmission projects in the Tehachapi Wind Resource Area ("TWRA") to the CAISO Controlled Grid.

The CAISO found that in addition to interconnecting several projects in the interconnection queue, the Tehachapi will provide system reliability and efficiency benefits. On January 24, 2007, the CAISO Board of Governors approved the entire Tehachapi Transmission Project and directed SCE, as the project sponsor, to proceed with the permitting and construction of the project.[2] The CAISO found, among other things, that the Tehachapi would lay the groundwork to integrate large amounts of planned geothermal, solar, and wind generation and would make possible in the future a low cost expansion of the transfer capability of Path 26, a major north-south transmission corridor.

The CPUC issued its final approval of the CPCN for Tehachapi Segment 1 on March 1, 2007;[3] the CPCN for Tehachapi Segments 2 and 3 on March 15, 2007;[4] and the CPCN for Tehachapi Segments 4-11 on December 17, 2009.[5] The CPUC found the proposed Project will: 1) support compliance with the State's RPS goals; 2) enable interconnection of wind generation projects in the Tehachapi region to SCE's transmission system; 3) eliminate existing constraints to the transmission of renewable energy from the Tehachapi region to Southern California; and 4) eliminate potential system-wide

[2] *See* CAISO Board of Governors Approval, SCE Application in Docket No. EL07-62, filed May 18, 2007, at Exhibit I.
[3] *See* CPUC Decision 07-03-012, March 1, 2007.
[4] *See* CPUC Decision 07-03-045, March 15, 2007.
[5] *See* CPUC Decision 09-12-044, December 17, 2009.

power flow and reliability problems due to overloading of the existing transmission system.

In its evaluation of Tehachapi Segments 1-3, the CPUC also studied energy efficiency and demand response alternatives. The CPUC concluded that, even with an increasing emphasis on energy efficiency and demand response, investments in transmission projects such as the proposed Antelope-Pardee Transmission Project (Segment 1) and the proposed Tehachapi-Vincent Transmission Project (Segments 2 and 3) will be needed both to enable California to meet RPS goals as well as to assure the continuing reliability and safety of the transmission grid in Southern California as renewable power generation and SCE customer demands increase. They further concluded that there is no alternative that can meet these needs better than the proposed Segments 1-3.[6] Segments 1-3A entered into service in 2009 and SCE is no longer collecting CWIP on these segments of the Tehachapi Project.

In addition, the CPUC concurred that Segments 4-11 would: (a) provide the electrical facilities necessary to reliably interconnect and integrate in excess of 700 megawatts ("MW") and up to approximately 4,500 MW of new wind generation in the TWRA currently being planned or expected in the future, thereby helping SCE and other California utilities in meeting California RPS goals; (b) further address the reliability needs of the CAISO-controlled grid due to projected load growth in the Antelope Valley; and (c) address the South of Lugo transmission constraints, an ongoing source of concern for the Los Angeles Basin.[7]

<u>Calcite</u>

On January 28, 2011, the FERC conditionally accepted the "Standard Large Generator Interconnection Agreement (LGIA) Among Abengoa Solar Inc. and Southern California Edison Company and California Independent System Operator Corporation"[8] for interconnection of a 250 MW solar thermal generating facility to SCE's existing Cool Water-Kramer No.1 220 kV line at a new SCE-owned 220 kV substation. On January 20, 2011, the FERC conditionally accepted the "Standard Large Generator Interconnection Agreement (LGIA) Among

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[6] *See* CPUC Segment 1 Approval, at p. 22, and CPUC Segments 2-3 Approval, at pp. 20-21.

[7] *See* CPUC Decision 09-12-044, Finding of Fact #18, page 93.

[8] *Southern California Edison Co.*, 134 FERC ¶ 61,059 (2011). The LGIA was conditionally accepted subject to the subject to the Commission decision regarding SCE's requested abandoned plant approval incentive in Docket No. EL11-10-000, which was approved on March 11, 2011. *Southern California Edison Co.*, 134 FERC ¶ 61,181 (2011).

Granite Wind, LLC. and Southern California Edison Company and California Independent System Operator Corporation"[9] for interconnection of a 60 MW wind generating facility to SCE's transmission system at the proposed Jasper 220 kV Substation.

SCE proposed construction of South of Kramer in order to remedy the reliability and congestion problems that would result from the development and interconnection of at least 591 MW of renewable solar and wind generation. The proposed facilities will be located in the Mojave Desert region of Southern California. Five projects had entered the CAISO interconnection process seeking interconnection, which triggered the need for the South of Kramer transmission facilities.

South of Kramer will also provide incremental transfer capability for other generation projects in the greater Mojave Desert region located near the Cool Water-Lugo and Lugo-Pisgah corridors. The South of Kramer project is complementary to SCE's Lugo-Pisgah project in a way that it provides additional transfer capability and collector substations to allow interconnection of currently proposed and future potential generation situated in the Barstow and Lucerne Competitive Renewable Energy Zones, as identified in reports prepared by the Renewable Energy Transmission Initiative ("RETI").[10] The Cool Water-Lugo transmission corridor has been identified by RETI and by the California Transmission Planning Group[11] as an important path for the transfer of location constrained renewable generation resources in the sparsely populated Mojave Desert to population centers in Southern California.

Through the CAISO's Interconnection System Impact Studies, SCE's existing transmission facilities were found to be inadequate to handle the proposed development of renewable generation in the area. In response to these studies, SCE proposed South of Kramer, which is needed to ensure reliability and full delivery of the renewable generation in the area as it is integrated into the grid.

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[9] *Southern California Edison Co.*, 134 FERC ¶ 61,032 (2011). The LGIA was conditionally accepted subject to the subject to the Commission decision regarding SCE's requested abandoned plant approval incentive in Docket No. EL11-10-000, which was approved on March 11, 2011. *Southern California Edison Co.*, 134 FERC ¶ 61,181 (2011).

[10] RETI is a statewide initiative intended to help identify the transmission projects needed to accommodate California's renewable energy goals. Background information about the purpose and formation of RETI, its mission statement, membership information, and all RETI documents are available at www.energy.ca.gov/reti.

[11] CTPG is a forum for conducting joint transmission planning and coordination in transmission activities in California. Background information on CTPG and all CTPG documents are available at ctpg.us/public/index.php.

Due to timing circumstances for the various elements of the South of Kramer Project, SCE modified the project during preparation of the CPCN application with the CPUC. The project was renamed the Coolwater-Lugo Transmission Project ("CWLTP") and a new substation, called Desert View, was added to the CPCN application to address load growth in the Victorville area along the path from Coolwater to Lugo Substation. Additionally, SCE did not include the Jasper Substation as part of the CPCN application because withdrawals from the CAISO's generator interconnection queue had eliminated the immediate need for SCE to move forward to license and develop that substation concurrently with CWLTP. However, the remaining elements of the CWLTP were the same as the originally proposed South of Kramer Project. SCE and generator signed LGIA in February 2016. The Jasper Substation was renamed the Calcite Substation and project development and licensing coordination are in progress.

On August 28, 2013, SCE filed a CPCN application and Proponent's Environmental Assessment (PEA) with the CPUC for the CWLTP. While the CPCN Application was pending before the CPUC, the CPUC and the CAISO received a letter stating that the Coolwater Generating Station would be shut down effective January 1, 2015. On March 17, 2015, the CAISO concluded that sufficient capacity was available in the area such that the CWTLP was no longer needed. On May 21, 2015, the CPUC dismissed SCE's CPCN application without prejudice.[12] Subsequently, on February 26, 2016, SCE filed a request under section 205 of the FPA to recover in its TO Tariff formula rate the prudently-incurred abandoned plant costs associated with the CWLTP.[13]

On January 10, 2017, SCE submitted an uncontested offer of settlement in the abandoned plant cost recovery proceeding between SCE and the intervening parties. Subsequently, on February 28, 2017, the settlement judge certified the settlement to the FERC as uncontested[14] and the uncontested settlement was approved by the Commission on April 10, 2017.[15]

<u>West of Devers</u>

On February 4, 2011, the FERC conditionally accepted the "Standard Large Generator Interconnection Agreement (LGIA) Among Palo Verde Solar II, LLC and Southern California Edison Company and California Independent System

[12] *See* CPUC Decision 15-05-040, May 21, 2015.
[13] *See* Docket No. ER16-1025.
[14] *Southern California Edison Co*., 158 FERC ¶ 63,006 (2017).
[15] *S. Cal. Edison Co*., 159 FERC ¶ 62,038 (2017).

Operator Corporation"[16] for interconnection of a 1,000 MW solar thermal generating facility to SCE's transmission system at the proposed Colorado River 220 kV Substation. In order to fully deliver this generating facility's output, additional network upgrades to SCE's transmission system are needed in Eastern Riverside County.

West of Devers will allow the delivery of at least 2,200 MW of renewable solar generation. The proposed facilities will be located in Eastern Riverside County, California. Five projects have entered the CAISO interconnection process seeking interconnection that trigger the need for West of Devers. Solar generation projects account for all of the 2,200 MW of proposed generation triggering the need for West of Devers. CAISO Phase II Studies have been performed for five new generation projects that will utilize West of Devers via the CAISO's cluster interconnection process. Additionally, the CAISO performed deliverability studies as part of Phase II, and determined that without West of Devers, the generation projects in queue utilizing West of Devers would not be fully deliverable.

The interconnection studies identified West of Devers as needed to enable fully deliverable renewable generation. West of Devers does not directly interconnect any new sources of generation; however, the upgrades are needed to allow full delivery of multiple generation projects interconnecting at SCE's new Colorado River and Red Bluff Substations.

On October 25, 2013, SCE filed a CPCN application with the CPUC. The proposed project has been reviewed under both the California Environmental Quality Act ("CEQA") and the National Environmental Policy Act ("NEPA").

On August 18, 2016, the CPUC approved the project in Decision D.16-08-017, including two alternatives.[17] Subsequently, the Bureau of Land Management ("BLM") approved the project with its Record of Decision ("ROD") on December 27, 2016.[18] The ROD includes a right-of-way grant decision and it applies only to BLM-administered lands.

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[16] *S. Cal. Edison Co.*, 134 FERC ¶ 61,087 (2011). The LGIA was conditionally accepted subject to the subject to the Commission decision regarding SCE's requested abandoned plant approval incentive in Docket No. EL11-10-000, which was approved on March 11, 2011. *Southern California Edison Co.*, 134 FERC ¶ 61,181 (2011).

[17] *See* CPUC Decision 16-08-017, August 18, 2016.

[18] *See* BLM Decision DOI-BLM-CA-060-0015-0021, CACA-055285

Whirlwind Substation Expansion

On February 17, 2011, the FERC conditionally accepted the "Standard Large Generator Interconnection Agreement (LGIA) Among AV Solar Ranch I, LLC and Southern California Edison Company and California Independent System Operator Corporation"[19] to interconnect a 250 MW solar photovoltaic generating facility to SCE's transmission system at the proposed Whirlwind Substation.

The expansion at Whirlwind provides capacity for an additional 2,000 megawatts (MW) of new generation resources. Whirlwind was originally planned as part of the Tehachapi project and it was designed for eventual expansion. At the time of SCE's petition in Docket No. EL07-62-000, however, the generators requesting interconnection at Whirlwind required a smaller subset of facilities to be constructed.

As of the end of 2010, additional generation resources have requested interconnection at Whirlwind, including four renewable generation projects, with a total capacity of 1,550 MW in the transition cluster, and an additional eight wind and solar generation projects, with a total capacity of 2,451 MW. The transition cluster is comprised of interconnection requests that were submitted on or before June 2, 2008, which are studied under a slightly modified version of the generation interconnection process reform. These additional resources have triggered the need for an expansion of Whirlwind. The Whirlwind expansion has already been approved by the CAISO and the CPUC as part of the Tehachapi project.

Colorado River Substation Expansion

As indicated above, the FERC conditionally accepted on February 4, 2011, the "Standard Large Generator Interconnection Agreement (LGIA) Among Palo Verde Solar II, LLC and Southern California Edison Company and California Independent System Operator Corporation" for interconnection of a 1,000 MW solar thermal generating facility to SCE's transmission system at the proposed Colorado River 220 kV Substation.

Colorado River expansion will provide capacity for up to 2,000 MW of new generation resources at Colorado River. The expansion will include both

[19] *Southern California Edison Co.*, 134 FERC ¶ 61,107 (2011). The LGIA was conditionally accepted subject to the subject to the Commission decision regarding SCE's requested abandoned plant approval incentive in Docket No. EL11-10-000, which was approved on March 11, 2011. *Southern California Edison Co.*, 134 FERC ¶ 61,181 (2011).

reliability network upgrades and delivery network upgrades. Colorado River was originally proposed to be configured as a 500 kV switchyard as a component of DPV2 and designed to be expanded as additional resources requested interconnection to the substation. Additional renewable generation projects have requested interconnection to the Colorado River 500 kV switchyard, including solar generation projects in the CAISO's transition cluster and additional interconnection requests for solar generation in subsequent queue clusters. Consequently, Colorado River needs to be expanded to accommodate such requests. The CPUC has previously approved Colorado River, however, the proposed expansion will require enlargement of the previously-approved project's footprint.

On November 3, 2010, SCE sought a permit to construct ("PTC") from the CPUC to construct an expansion to the Colorado River Substation in order to interconnect the 1,000 MW Blythe Solar Power Project and the 250 MW Genesis Solar Energy Project to the CAISO-controlled transmission grid. No protests were filed.

On July 14, 2011, the CPUC granted SCE a permit to construct the Colorado River Substation expansion project with the mitigation measures attached to this order.[20]

Mesa Substation

Mesa has been reviewed and approved by the CAISO through its 2013-2014 TPP as a reliability project needed to address reliability concerns resulting from the permanent retirement of the SONGS in 2013 and from OTC generation shutdowns expected by December 31, 2020.[21] Mesa will help address these concerns by allowing for greater flexibility in the siting of future generation to meet local reliability needs in the western Los Angeles Basin, while reducing the

[20] *See* CPUC Decision 11-07-011, July 14, 2011.

[21] OTC facilities are generating plants that take in ocean or estuarine water to cool their turbines and return the water back to the source. California State Water Resource Control Board's (SWRCB) OTC Policy outlines a state-wide compliance schedule to reduce the environmental impact of these facilities, which involves the planned retirement of specific OTC plants within the Los Angeles Basin by the end of 2020. For more information see
http://www.swrcb.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml
2013-2014 ISO Transmission Plan (July 16, 2014), available at
http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan_July162014.pdf; at p. 6.

total amount of new generation required by providing additional transmission import capability.

Mesa involves demolishing the existing 220/66/16 kV Mesa Substation and constructing a new large 500/220/66/16 kV substation and includes both network transmission facilities as well as distribution, i.e., non-network facilities. It is contemplated that certain 500 kV and 220 kV transmission facilities would be under the Operational Control of the CAISO and subject to the requested incentives.

On March 13, 2015, SCE sought a PTC from the CPUC to address reliability concerns by providing additional transmission import capability, allowing greater flexibility in the siting of new generation, and reducing the total amount of new generation required to meet local reliability needs in the Western Los Angeles Basin area.

On February 9, 2017, the CPUC issued a final decision approving the project largely consistent with SCE's proposal and rejected alternative project configurations proposed by CPUC staff.[22] In October 2017, SCE awarded the competitive bid for the new 220 kV portion of substation construction. SCE updated the expected cost of the Project due to schedule delays and scope changes. The remainder (500 kV portion of substation construction) will be put out for bid by early 2019 and SCE expects that costs associated with the project may change as a result of the competitive bidding process.

Alberhill System

Alberhill has been reviewed and approved through the CAISO's 2009 TPP as a reliability project to serve current and projected demand for electricity and maintain electric system reliability in portions to the southeast of Alberhill Substation and south of Valley Substation, including the cities of Lake Elsinore, Canyon Lake, Perris, Menifee, Murrieta, Murrieta Hot Springs, Temecula, and Wildomar, as well as the surrounding unincorporated portions of Riverside County. CAISO found that the project was the "most robust transmission alternative with expected minimum environmental impact in meeting reliability needs and providing long-term transformer capacity for serving load growth in the southwestern Riverside County."[23]

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[22] *See* CPUC Decision 17-02-015, February 9, 2017.

[23] *See CAISO Memorandum to ISO Board of Governors* regarding the decision on Alberhill Substation Project, December 9, 2009.

Alberhill would relieve the Valley South 115 kilovolt (kV) system by transferring five existing 115/12 kV substations (Ivyglen, Fogarty, Elsinore, Skylark and Newcomb 115 kV substations) to the new Alberhill system. Alberhill will include construction of the following facilities: (1) a new 500/115 kV substation with 500 kV switchrack and two three-phase 500/115 kV transformers; and (2) two new 500 kV transmission line segments (3.3 miles in length) to connect the new substation to SCE's existing Serrano-Valley 500 kV line. It is contemplated that the 500 kV switchrack and 500 kV transmission line segments would be under the Operational Control of the CAISO and subject to the requested incentives.

On September 30, 2009, SCE filed its CPCN application with the CPUC to construct the Alberhill System Project to relieve projected electrical demand that would exceed the operating limit of the two load-serving Valley South 115 kV system 500/115 kV transformers within the electrical needs area, and to provide electricity in place of the Alberhill 115 kV system during maintenance, during emergency events, or to relieve other operational issues on one of the system.

On April 2, 2013, SCE proposed a modification to the previously-approved permit to construct the Valley-Ivyglen 115 kV Subtransmission Line Project (Valley-Ivyglen Project), which purpose is to relieve loads on the existing Valley-Elsinore-Fogarty 115 kV Subtransmission Line and provide a second source of power to Ivyglen Substation.[24] Specifically, SCE sought to modify the project design by, among other things, realigning portions of the subtransmission line route and undergrounding a portion of the line and to modify the construction method and techniques by, among other things, using shooflies, blasting, and helicopters.

In April 2018 and July 2018, the CPUC issued a proposed decision and an alternate proposed decision, both denying SCE's ability to construct the Alberhill System Project based on a perceived lack of need. SCE filed comments on both proposed decisions requesting that the CPUC grant the certificate of public convenience and necessity for the Alberhill System Project.

In August 2018, the CPUC directed SCE to submit supplemental information on the Alberhill System Project including details of demand and load forecasts and possible alternatives to the proposed project.[25] Ongoing capital spending has been deferred as a result of the CPUC request for additional information and alternatives. Given the uncertainty associated with the resolution of the permitting process, potential revisions to the project have not been reflected

[24] *See* CPUC Decision 10-08-009, August 12, 2010.
[25] *See* CPUC Decision 18-08-026, August 23, 2018.

in total direct expenditures. SCE continues to believe the Alberhill System Project is needed and is unable to predict the timing of a final CPUC decision in connection with the Alberhill System Project.

Eldorado-Lugo-Mohave Upgrade

CAISO approved the Lugo-Eldorado series capacitor and terminal equipment upgrade in its 2012-2013 TPP and the Lugo-Mohave series cap and terminal equipment upgrade in its 2013-2014 TPP as policy-driven upgrades to relieve deliverability constraints in order to support achievement of California's renewable goals. It will increase power flow through existing transmission lines from Nevada to Southern California and provides renewable integration, deliverability and reliability benefits. CAISO identified reliability benefits of the project in that it relieves overloads on certain 500kV facilities in the neighboring Los Angeles Department of Water and Power's (LADWP's) transmission system.

The ELM project would modify SCE's existing Eldorado, Lugo, and Mohave electrical substations to accommodate the increased current flow from Nevada to Southern California; increase the power flow through the existing Eldorado-Lugo, Eldorado-Mohave, and Lugo-Mohave 500 kV transmission lines for the purpose of increasing the amount of power delivered from California's Ivanpah Valley, Nevada, and Arizona to the Electrical Needs Area (ENA) through the SCE system in an effort to meet requirements associated with the California Renewables Portfolio Standard (RPS) by constructing two new 500 kV mid-line series capacitors (i.e., the proposed Newberry Springs Series Capacitors and Ludlow Series Capacitors) and associated equipment; raise transmission tower heights to meet ground clearance requirements; and install communication wire on SCE's transmission lines to allow for communication between existing SCE substations.

SCE has proposed an expedited schedule and a non-standard review process with the regulatory permitting agencies in order to meet the current in-service date. During September 2017, SCE awarded the competitive bid for the project which resulted in a decrease to the expected capital forecast for the project.

On May 2, 2018, SCE filed an application for a PTC authorizing SCE to construct electrical facilities known as the Eldorado-Lugo-Mohave Series Capacitor Project.

On January 9, 2019, the CPUC directed SCE to file an amended application for a CPCN. SCE is currently assessing the impact of this decision on the timing and the cost of the project.[26]

[26] *See* CPUC Ruling on Application 18-05-007, January 9, 2019.

ATTESTATION BY

AARON D MOSS,

VICE PRESIDENT

ATTESTATION

Aaron D Moss attests that he is Vice President of Southern California Edison Company, and that the cost of service statements and supporting data submitted as a part of this filing which purport to reflect the books of Southern California Edison Company are true, accurate, and current representations of the utility's books and other corporate documents to the best of his knowledge and belief.

Aaron D Moss

Vice President

Dated: April 5, 2019

REVISED CLEAN VERSION OF

SCE’S TO TARIFF SHEETS

REFLECTING THE PROPOSED

FORMULA RATE

APPENDIX IX

ATTACHMENT 1

FORMULA RATE PROTOCOLS

1. INTRODUCTION

SCE shall calculate its Base Transmission Revenue Requirement ("Base TRR"), as defined in Section 3.6 of the main definitions section of this TO Tariff, using the formula rate that is presented in spreadsheet format in Attachment 2 to Appendix IX ("Formula Rate Spreadsheet").[1] The Formula Rate Spreadsheet contains fixed formulae that are only subject to change pursuant to Sections 205 and 206 of the Federal Power Act, and will be populated with data from SCE's annual Federal Energy Regulatory Commission ("FERC" or the "Commission") Form 1 filing or from other SCE records. The sources of the data used in the Formula Rate will be: (a) identified in the Formula Rate Spreadsheet by fixed references to specific locations in FERC Form 1, or (b) provided by SCE in accordance with Section 3 of these Protocols.

The Base TRR shall be calculated annually in accordance with the Formula Rate and shall be equal to the sum of the Prior Year TRR, the Incremental Forecast Period TRR, and the True Up Adjustment. Additionally, SCE shall include a Cost Adjustment in the Base TRR for the upcoming Rate Year in the event that a discrete cost of service item (e.g., individual O&M expense, tax expense, or revenue credit) incurred anytime between the beginning of the Prior Year and the September 30 immediately preceding the Annual Update filing (i.e., a 21 month window) is a one-time item that will not recur in such Rate Year. Individual items shall not be aggregated for purpose of determining a discrete cost of service item. The discrete cost of service item must amount to at least 3% of the Base TRR in such Annual Update filing in order for a Cost Adjustment to be included as a component of the Base TRR. The Cost Adjustment shall be handled as follows:

a) 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. For example, if the discrete cost of service item is a $100 million one-time property tax refund (a negative item) received during 2012 but which will not recur during 2014, + $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. If the discrete cost of

[1] Attachment 2 consists of thirty-four (34) individual Schedules. All references in the Formula Rate Protocols ("Protocols") to Schedules refer to Schedules in the Formula Rate Spreadsheet. The Formula Rate Spreadsheet and Formula Rate Protocols together comprise the "Formula Rate." The formula rate that was in effect from January 1, 2012 through December 31, 2017 pursuant to Docket No. ER11-3697 shall be referred to herein as the "Original Formula Rate", and the formula rate that went into effect on January 1, 2018 pursuant to Docket No. ER18-169, through the effective date of this Formula Rate shall be referred to herein as the "Second Formula Rate".

service item is a $100 million one-time O&M cost (a positive item) incurred during 2012 that will not recur in 2014, - $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. Both examples assume the 3% threshold is met.

b) If the discrete cost of service item occurred between January 1 and September 30 of the year in which the Annual Update filing is submitted to FERC (i.e., the year before the upcoming Rate Year), then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude and the same sign as the discrete cost of service item. For example, if the discrete cost of service item is a $100 million one-time property tax refund (a negative item) received during the first nine months of 2013 but which will not recur during 2014, - $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. If the discrete cost of service item is a $100 million one-time O&M cost (a positive item) incurred during the first nine months of 2013 that will not recur in 2014, + $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. Both examples assume the 3% threshold is met.

If SCE includes a Cost Adjustment in its Base TRR, SCE shall include with its Annual Update an explanation of its belief that the discrete cost of service item that is the subject of such Cost Adjustment will not recur in the upcoming Rate Year.

The Wholesale Base TRR is equal to the Base TRR adjusted as follows (as set forth in Schedule 25): (1) Uncollectibles Expense is not included in the Wholesale Base TRR; (2) the Wholesale Rate Base Adjustment and associated Wholesale Expense Difference is included in the Wholesale TRR; (3) EEI dues and EPRI dues are excluded from the Wholesale Base TRR; and (4) Franchise Fees Expense included in the Wholesale Base TRR is lower than that included in the Base TRR due to the Franchise Fee Factor being applied to a lower Base TRR.

2. TERM OF THE FORMULA RATE

The Formula Rate shall become effective on the date the Commission determines, and SCE's Base TRR shall be subject to true up beginning on that date in accordance with these Protocols. Retail and Wholesale transmission rates shall become effective on the date the Commission determines, and shall be redetermined annually in accordance with these Protocols and the Formula Rate Spreadsheet. The Formula Rate will remain in effect without termination unless and until SCE files pursuant to Section 205 of the Federal Power Act to replace the Formula Rate with a successor transmission rate mechanism and the Commission accepts such successor transmission rate mechanism. This Formula Rate shall remain in effect until the date that the successor rate mechanism filing is made effective by the Commission.

3. PROCEDURES FOR UPDATING THE BASE TRR

For as long as this Formula Rate is in effect, SCE shall update its Base TRR for the upcoming Rate Year[2] according to the timeline and procedures described in this Section. A summary of the procedures for updating the Base TRR is set forth in the following table:

Event	Date
Posting Date of Draft Annual Update	June 15
Start of Information Requests	June 15
Draft Annual Update Conference	June 15 – July 15
End of Information Requests	November 1
Annual Update filed with FERC	December 1
Rate Goes into Effect	January 1

a) Draft Annual Update

On or before June 15 of each year, SCE will post to its website (www.sce.com) its Draft Annual Update and will provide electronic notice of such posting to the Service List.[3] The Draft Annual Update shall set forth the Base TRR for the upcoming Rate Year, and shall include populated versions of all Schedules comprising the Formula Rate in their native format with all formulas and links intact. In addition to the foregoing, the Draft Annual Update shall include the following:

1) All workpapers used in the calculation of the Base TRR. The workpapers shall be provided in their native format, with all formulas and links intact.

2) The Plant Study described in Section 9 of the Protocols in native format with all formulas and links intact, along with all workpapers prepared in support of the plant study, and a description of any changes in the methodology used to perform the Plant Study as compared with the Prior Year's Annual Update.

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[2] "Rate Year" shall mean the twelve consecutive month period of January 1 through December 31 that corresponds to the year for which charges are assessed under the Formula Rate.

[3] The "Service List" includes (1) any state regulatory agency with jurisdiction over the rates, charges or services of SCE; (2) any person or entity admitted as a party to this Formula Rate proceeding; and (3) any person or entity admitted as a party in any Annual Update proceeding filed by SCE in accordance with these Protocols. For purposes of communications with parties on the Service List, SCE will include the individuals on the service list in the Docket in which this Formula Rate is filed, and parties that are admitted in future FERC proceedings involving Formula Rate Annual Updates. Any references to a "party" in these Protocols shall mean any party to the Docket in which this Formula Rate is filed and any party admitted to future FERC proceedings involving Formula Rate Annual Updates.

3) Workpapers supporting the inputs that appear in Schedule 27 in equivalent form to the workpapers provided in FERC Docket No. ER11-3697, Volume 4, Workpapers for Exhibit SCE-600, pages 1-268.

4) Workpapers that demonstrate the historical corporate overhead expenses recorded for ISO projects by Project Identification Number (PIN) that closed in the prior year and have accumulated ISO project costs greater than $5 million.

5) Workpapers that demonstrate the derivation of the AFUDC rates applicable to all projects in the prior year.

6) Workpapers supporting the forecasted gross plant expenditures shown on Schedule 16.

7) A statement that identifies each ISO project (PIN) with total direct expenditures (recorded and forecast) greater than $5 million projected to go into rate base during the forecast period. The statement will also include the monthly budgeted direct expenditures, to the extent such currently projected costs are shown on the most recent applicable SCE budget documents, and the total project cost of each project.

8) Workpapers showing the beginning of year and end of year outstanding network upgrade credits, as well as interest on network upgrade credits that is recorded in Account 252 listed by entity due those credits. The workpapers shall be provided in equivalent form to the workpapers entitled "Workpapers for Exhibit SCE-800" provided by SCE in FERC Docket No. ER11-3697.

9) Workpapers showing forecast period incentive Construction Work in Progress ("CWIP") projects by PIN and by month that support the values in Schedule 10 at lines 29-70 in equivalent form to the workpapers provided in FERC Docket No. ER11-3697, Volume 3, Workpapers for Exhibit SCE-500, pages 149-175.

10) A description of any Material Accounting Changes contained in the Draft Annual Update.[4]

[4] "Material Accounting Changes" shall mean any material change that affects SCE's transmission rates as follows: (i) accounting policies and practices from those in effect for the Prior Year upon which the immediately preceding Annual Update was based, including those resulting from any new or revised accounting guidance from the Financial Accounting Standards Board; or (ii) internal corporate cost allocation policies or practices in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iii) income tax elections from those in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iv) cost allocation policies between EIX, SCE, and subsidiaries of either, from those in effect for the Prior Year upon which the immediately preceding Annual Update was based. Additionally, a Material Accounting Change shall also include any: (i) initial implementation of an accounting standard; or (ii) initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction.

11) A workpaper describing the nature and amount of each project/activity, the costs of which are booked to Account 930.2 and which are recovered under the Formula Rate. 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).

12) A workpaper identifying each discrete A&G cost item that has been excluded from Schedule 20 of the Formula Rate (including both "positive exclusions" and "negative exclusions"), together with a summation of such items by account.

13) A description of any facilities SCE projects will change classification between CPUC and CAISO jurisdictions through the Rate Year. This description should include an estimated date for when the project will change classification, the reason for the classification change, and the proposed future rate recovery (*i.e.*, whether through FERC or CPUC rates).

b) Draft Annual Update Conference

SCE will provide notice to parties on the Service List of a one-day meeting, to take place on or before July 15 of each year, to discuss the Draft Annual Update. By mutual agreement of SCE and the parties on the Service List, such a meeting may take place in-person, via telephone, or video-conference. SCE shall make appropriate personnel available for such meeting. Additional meetings to discuss the Draft Annual Update shall be scheduled as SCE and the parties on the Service List may mutually agree**.**

c) Information Requests

1) At any time from June 15 until November 1, parties on the Service List may submit reasonable information requests to SCE regarding the Draft Annual Update.

2) SCE shall make a good faith effort to respond to information requests in writing within ten (10) business days of receipt. Alternatively, if SCE in good faith believes that the information request is unreasonable, SCE may object to the request. SCE shall contemporaneously provide copies of all responses to all parties on the Service List that have indicated to SCE that they wish to receive such copies. If SCE objects to an information request, then SCE shall make a good faith effort to provide its objections within ten (10) business days of receipt of the information requests to the party serving the request. SCE shall include in its objection the basis for the objection. SCE and the party serving the information request on SCE will work cooperatively and in good

faith to resolve any questions, objections, or disputes relating to the information requests.

3) Responses to information requests shall not be designated as settlement communications or produced under the Commission's rules and regulations governing settlements, unless provided as a privileged settlement communication in a Commission proceeding being conducted under the Commission's settlement rules. SCE may mark materials provided in response to an information request as Protected Materials in accordance with Exhibit A to the Protocols. To the extent an information request response calls for the production of Protected Materials, SCE will only provide such materials to the parties with whom it has entered into a non-disclosure agreement that is included in Exhibit A.

4) To the extent SCE and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Protocols, SCE or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. Neither SCE nor any interested party shall object to a request for a Discovery Master. The discovery master shall have the power to issue orders to resolve discovery disputes, as appropriate, in accordance with these Protocols and consistent with the FERC's discovery rules. The discovery master's orders shall be subject to appeal to the Commission and to the courts to the same extent and under the same rules as would be applicable to an Initial Decision issued under Rule 708 of the Commission's Rules of Practice and Procedure. In the event the Commission establishes hearing procedures for an Annual Update, the discovery master's responsibilities shall be transferred to the Presiding Judge for such hearing effective upon his or her appointment.

d) Annual Update

1) On or before December 1 of each year, SCE shall file with the Commission its Annual Update setting forth the Base TRR and associated rates for the upcoming Rate Year. It is expressly intended by these Protocols that the Commission will issue public notice of the Annual Update inviting public comment, and SCE shall request in its Annual Update filing that the Commission issue public notice of the Annual Update inviting public comment.

2) SCE shall identify in the Annual Update any corrections or other changes to the Draft Annual Update, and shall provide an explanation of the reason for the changes. SCE shall also include in the Annual Update any changes to the Draft Annual Update that it and any other party have agreed upon as of November 15.

3) The Annual Update shall not modify the Formula Rate or subject the Formula Rate to modification, and shall not constitute a rate change filing under Section 205 of the Federal Power Act. Any party may challenge the justness and reasonableness of SCE's implementation of its Formula Rate with respect to: (a) whether SCE has properly and reasonably applied the Formula Rate Spreadsheet and the procedures in these Protocols; (b) whether the costs to be recovered have been accurately stated, properly recorded and accounted for pursuant to applicable FERC accounting practices and procedures; (c) whether the costs to be recovered through the Base TRR and associated rates have been or will be prudently incurred; (d) whether SCE's projections have been reasonably made; (e) whether its calculation methodologies are consistent with the Formula Rate; (f) whether SCE has made the required filings under Section 8(a) of these Protocols to reflect any intervening change(s) to the Uniform System of Accounts or FERC Form 1; and (g) whether any Material Accounting Changes are reasonable and consistent with the Uniform System of Accounts.

4) The Base TRR set forth in the Annual Update and associated rates shall be effective on January 1 of the upcoming Rate Year.

5) Any party may comment on or protest the Annual Update. Any party may request that FERC establish hearing and/or settlement procedures regarding an Annual Update, and all parties reserve their rights to oppose such requests on their merits, but may not object to such requests on the basis that hearing and/or settlement procedures are prohibited by these Protocols or the Formula Rate Spreadsheet. Nothing in these Protocols shall act as a bar to a party raising an issue in comments or in protests to the Annual Update that it has not raised in a prior Annual Update proceeding (including pre-filing phases of such proceeding) or with respect to which it has not previously exercised its rights under the Federal Power Act. It is expressly intended by these Protocols that FERC issue an order taking action, assuming any action is requested, on the Annual Update if protests and/or comments on the Annual Update are filed.

6) In any Annual Update proceeding, SCE shall bear the burden, consistent with Section 205 of the Federal Power Act, of showing the justness and reasonableness of the implementation of its Formula Rate by demonstrating that: (a) it has properly and reasonably applied the Formula Rate Spreadsheet and the procedures in these Protocols; (b) the costs to be recovered have been accurately stated, properly recorded and accounted for pursuant to applicable FERC accounting practices and procedures; (c) its projections have been reasonably made; (d) its calculation methodologies are consistent with the Formula Rate; and (e) any Material Accounting Changes are reasonable and consistent with the Uniform System of Accounts; Nothing herein is intended to alter the burden of proof applied by the Commission with respect to prudence.

7) SCE will make any revisions to the Base TRR and associated rates that are required by a final[5] Commission order with respect to each Annual Update. Unless otherwise ordered by the Commission, such revisions shall be effective as of the first day of the applicable Rate Year and shall be reflected, with interest calculated pursuant to the interest rate in Section 35.19a of the Commission's regulations, in the next subsequent Annual Update as a component of the True Up Adjustment. If the term of the Formula Rate is expiring so that there will be no future Annual Update, SCE shall include the TRR difference in the Final True Up Adjustment.

8) 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 that affected the True Up TRR calculated in that Annual Update, including but not limited to filed corrections to its FERC Form 1 that affect inputs to the Formula Rate, or errors in other input data used in determining the True Up TRR, SCE shall promptly serve notice to the Commission in the docket of the affected Annual Update that SCE intends to file an Amended Annual Update, with a brief description of the errors to be corrected in such filing. SCE shall additionally notify the entities that have participated in SCE's Annual Update filings of the errors and the upcoming Amended Annual Update. The Amended Annual Update shall:

   i recalculate the True Up TRR for all affected Prior Years;

   ii compare, on a monthly basis, the difference between the initial incorrect True Up TRR and the revised correct True Up TRR; and

   iii determine the cumulative amount of the difference in (ii), including interest calculated pursuant to the interest rate in 18 C.F.R. § 35.19a.

The difference in (iii) shall be included as an additional component to SCE's True Up Adjustment in the subsequent Annual Update as a One Time True Up Adjustment in accordance with the Formula Rate.

If the difference in (iii) would not result in an increase to the True-Up TRR of more than $1 million, however, then SCE need not submit to the Commission an Amended Annual Update, as described above, but may include the difference in (iii) in its Draft Annual Update, or, if the error is discovered after the posting of a Draft Annual Update on June 15, in an amended Draft Annual Update posted on SCE's website no later than October 31.

[5] All references in these Protocols to Commission orders or actions refer to the final form of such orders or actions (in accordance with the Federal Power Act and applicable Commission regulations, including without limitation Commission regulations with respect to a stay of a Commission order upon rehearing and/or an appeal), including as they may be modified as a result of a request for rehearing or Court appeal.

In the event that SCE has identified multiple input errors, SCE shall identify each such error and its correction individually. The amount proposed to be included in an Amended Annual Update, a Draft Annual Update, or an amended Draft Annual Update as a One Time True Up Adjustment shall be subject to scrutiny through the information exchange process and annual update procedures described in this Section 3.

4. THE ANNUAL TRUE UP ADJUSTMENT AND THE FINAL TRUE UP ADJUSTMENT

The Annual True Up Adjustment component of the Base TRR ensures that during the time the Formula Rate is in effect, SCE will recover its actual costs of owning and operating its ISO transmission facilities, as defined by the True Up TRR. The Annual True Up Adjustment is calculated for each Annual Update for the previous calendar year (the "Prior Year"), if the Formula Rate, or a previous formula rate, was in effect during some or all of that year, through the following steps:

a) Calculate SCE's actual costs during the Prior Year, as measured by the "True Up TRR." The True Up TRR, as defined in the Formula Rate, is equal to the Prior Year TRR as defined in the Formula Rate, except that all of the Rate Base components used in the True Up TRR are based on 13-month average values or beginning-of-year and end-of-year average values.

b) Attribute the True Up TRR to each month of the Prior Year as specifically defined in the Formula Rate.

c) Determine SCE's actual retail base transmission revenues attributable to the Formula Rate on a monthly basis for each month of the Prior Year, in accordance with the Formula Rate.

d) Compare SCE's monthly True Up TRR to SCE's monthly actual retail base transmission revenues. Each monthly difference shall be cumulated, including interest calculated on a monthly basis using the interest rate specified in the regulations of the Commission at 18 C.F.R § 35.19a, through the end of the Prior Year, in accordance with the Formula Rate to determine a "Shortfall or Excess Revenue in the Prior Year". The "Shortfall or Excess Revenue in the Prior Year" shall also include the "Shortfall or Excess Revenue in the Prior Year" from the previous Annual Update, as specifically included in Schedule 3 of the Formula Rate Spreadsheet, Schedule 3, Line 11, and any applicable One Time Adjustments.

e) As stated in Section 6 below, the True Up Adjustment included in the Base TRR effective January 1, 2018 shall include the Final True Up Adjustment for the 2016 year calculated pursuant to the Original Formula Rate. The Final True Up Adjustment for the 2017 year calculated pursuant to the Original Formula Rate shall be included in the True Up Adjustment for the Annual Update submitted by December 1, 2018. The True Up Adjustment included in the Base TRR effective January 1, 2020 shall include the Final True Up Adjustment for the 2018 year calculated pursuant to the Second Formula Rate. The True Up Adjustment included in the Base TRR effective January 1, 2021 shall include the Final True Up Adjustment for the portion of the 2019 year for which the Second Formula

Rate was in effect, calculated pursuant to the Second Formula Rate.

In the event that this Formula Rate terminates, 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 on December 31, 2030, SCE will determine a Final True Up Adjustment in 2031 for calendar year 2030. 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 this 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.

5. THE INCREMENTAL FORECAST PERIOD TRR

The Incremental Forecast Period TRR ("IFPTRR"), calculated in Schedule 2 (Incremental Forecast Period TRR) of the Formula Rate Spreadsheet, is a component of SCE's Base TRR that represents the amount of transmission revenue requirement that SCE anticipates during the upcoming Rate Year that is incremental to that reflected in the Prior Year TRR as a result of additions of plant in service (identified in Schedule 16 (Plant Additions) of the Formula Rate) and/or CWIP expenditures (identified in Schedule 10 (CWIP) of the Formula Rate) to Rate Base. The IFPTRR shall be calculated in accordance with the Formula Rate.

6. TRANSITION OF THE ORIGINAL AND SECOND FORMULA RATES TO SUCCESSOR FORMULA RATES

Pursuant to Section 4 of the Formula Rate Protocols for the Original Formula Rate, SCE is entitled and required to reflect the amount of any Final True Up Adjustment from the Original Formula Rate for the 2016 and 2017 years in its successor transmission rates. This Section 6 ensures that this requirement from the Original Formula Rate is implemented accurately.

The Formula Rate Base TRR and associated rates for the Rate Years 2018 and 2019 shall reflect a True Up Adjustment that is based on a True Up TRR for the years 2016 and 2017 respectively calculated pursuant to the Original Formula Rate. This shall be implemented in the rate filing for the 2018 Rate Year and the Annual Update for the 2019 Rate Year by including as a "One Time Adjustment" any difference in the True Up TRR for the Prior Years of 2016 and 2017 calculated under this Formula Rate and the True Up TRR amounts calculated pursuant to the Original Formula Rate in Column 4 of Schedule 3 of the Formula Rate Spreadsheet. The One Time Adjustment included in the 2018 Rate Year filing will reflect the difference between the 2016 year True Up TRR calculated pursuant to the Second Formula Rate and the Original Formula Rate. The Annual Update for the 2019 Rate Year will reflect the difference between the 2017 year True Up TRR calculated pursuant to the Second Formula Rate and the Original Formula Rate. The 2017 True Up TRR calculated pursuant to the Original Formula Rate shall include an amount of Excess Deferred Income Taxes for year-end 2017 relating to the 2017 Tax Cuts and Jobs Act as a component of the calculation of Accumulated Deferred Income Taxes ("ADIT") in Schedule 9 of the Formula Rate Spreadsheet created as a result of the change in the Federal Income Tax Rate. Such amount shall be included along with Account 190, 282, and 283 amounts in the calculation of End-of-Year "Total Accumulated Deferred Income Taxes" on Line 4 of Schedule 9.

Additionally, any transition from one formula rate to its successor formula rate shall ensure that the True Up TRRs for any years for which a previous formula rate or formula rates were in effect during all or part of that year are calculated utilizing the formula rate, or formula rates, that were in effect during the year being trued up. This shall be implemented through a "One Time Adjustment" reflecting the difference between the True Up TRR calculated using the Formula Rate in effect at the time of the Annual Update, and the True Up TRR calculated pursuant to the formula rate, or formula rates, that were in effect during the year being trued up. In the event that any year being trued up has two or more formulas in effect during that year, the True Up TRR for that year shall be based on a weighted average of the True Up TRRs calculated pursuant to the formula rates in effect that year, with the weighting being based on the number of days during the year that each was in effect. Any Annual Update which includes a Final True Up Adjustment for a previous year shall include a workpaper with a calculation of the associated One Time Adjustments.

7. DEPRECIATION RATES

Depreciation rates for Transmission Plant, Distribution Plant, General Plant, and Intangible Plant shall be as stated in the Formula Rate Spreadsheet.

8. REVISIONS TO CERTAIN FORMULA RATE PROVISIONS

SCE will be required to make single-issue Section 205 filings to change the Formula Rate as provided in Section 8, parts (a) through (e). In addition to the single-issue filings provided for in this Section 8 and subject to the limitations set forth in Section 11, SCE may make Section 205 filings that present only a single issue or limited discrete issues for consideration by the Commission, *i.e*., proposing to change any one or more elements of its Formula Rate. Such filings shall not be governed by the provisions of this Section 8, and the parties and SCE reserve their rights with respect to any such filing.

In a proceeding commenced by such a single-issue Section 205 filing under Section 8, parts (a) and (b), the sole issues that can or shall be addressed are whether the changes proposed by SCE are consistent with these Protocols and are just and reasonable.

In a proceeding commenced by a single-issue filing under Section 8, part (c), the sole issues that can or shall be addressed are whether the changes proposed by SCE are just and reasonable and correctly implement the applicable California Public Utilities

Commission (“CPUC”) order.

In a proceeding commenced by a single-issue filing under Section 8, parts (d) and (e), the sole issue that can or shall be addressed is whether the changes proposed by SCE correctly implement the applicable CPUC order.

The proceedings commenced in response to the filings described in this Section shall not include or allow for consideration or examination of any other aspects of the Formula Rate or other issues associated with the Formula Rate, except to the extent that the proposed changes directly impact other Formula Rate components that are not the subject of the single-issue filing. All parties will have all applicable rights under the Federal Power Act and FERC’s regulations with respect to such single-issue Section 205 filings, except as limited by this Section 8.

a) SCE will make a single-issue Section 205 filing to update the references in the Formula to reflect any changes to the format and/or content of the FERC Form 1 or the Uniform System of Accounts that affect the calculations set forth in the Formula in the event that a Commission order revises the format and/or content of the FERC Form 1 or the Uniform System of Accounts. This filing shall be submitted within sixty days of the implementation of any FERC decision to revise the FERC Form 1 or the Uniform System of Accounts, and shall be effective on the date of the revisions to the FERC Form 1 or Uniform System of Accounts, as applicable.

b) With respect to Post-Retirement Benefits Other than Pensions (“PBOPs”), the Formula Rate identifies an Authorized PBOPs Expense Amount in Note 3 on Schedule 20 (Administrative and General Expenses). SCE shall make a single-issue Section 205 filing by April 1 of each year to revise the Authorized PBOPs Expense Amount, seeking an effective date of January 1 of the year of the filing.

c) 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, as set forth in this Section, between January 1 and March 1 of the year following the year that the CPUC order became effective.

d) SCE will make a single-issue Section 205 filing to revise Schedule 33 of the Formula Rate determination of retail transmission rates to reflect any change in Rate Groups, Rate Schedules, or the design of retail rates applicable to each Rate Schedule subsequent to any final CPUC order that affects these aspects of retail transmission rates. SCE will make such a filing only if and when the change in Rate Groups, Rate Schedules, or the design of retail rates cannot otherwise be reflected through the normal operation of the Formula Rate. In the single-issue Section 205 filing to the Commission, SCE will propose revisions to Schedule 33 of the Formula Rate that conform to the CPUC order. SCE will make a filing under this Section 8(d) by the later of either the filing date for the next Annual Update following the CPUC ruling or sixty days after the CPUC ruling.

e) 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.

9. DETERMINATION OF AMOUNT OF TRANSMISSION PLANT - ISO AND DISTRIBUTION PLANT - ISO

SCE shall perform for the Prior Year a study ("Plant Study") to determine:

- The amount of plant classified as Transmission in SCE's annual FERC Form 1 filing that is under the Operational Control of the ISO. Such amount shall be called Transmission Plant - ISO; and
- The amount of plant classified as Distribution in SCE's annual FERC Form 1 filing that is under the Operational Control of the ISO. Such amount shall be called Distribution Plant - ISO.

The Plant Study determination of Transmission Plant - ISO and Distribution Plant - ISO will correspond to the end-of-year plant values for transmission and distribution published in SCE's FERC Form 1, and also shall be based on actual end-of-year ISO Operational Control of facilities. SCE will identify in the Plant Study major transmission facilities that have moved to or from ISO Operational Control in the Prior Year. Additionally, in submitting its future CPUC General Rate Case applications, SCE shall exclude from its CPUC-jurisdictional cost of service forecast, the cost of transmission and distribution facilities that SCE projects will be under the Operational Control of the ISO during the test year.

The methodology used in the Plant Study to determine Transmission Plant - ISO and Distribution Plant - ISO shall be as follows:

a) For each Transmission account 350-359 and Distribution account 360-362, identify the year-end recorded gross plant amount.

b) For Transmission accounts 350-359 and Distribution accounts 360-362, classify the assets by each location into one of the following categories:

   1) All ISO: All Transmission or Distribution assets at the location are under the Operational Control of the ISO.

   2) Non-ISO: No Transmission or Distribution assets at the location are under the Operational Control of the ISO.

   3) Mixed ISO and Non-ISO Substation: The Transmission or Distribution substation location has a mixture of assets under the Operational Control of the ISO and assets that are not under the Operational Control of the ISO.
   4) Mixed ISO and Non-ISO Line: Transmission line locations that have a mixture of assets under the Operational Control of the ISO and assets that are not under the Operational Control of the ISO that need to be analyzed

using the Transmission Line methodology.

5) Other: Assets for which there is not sufficient data to categorize into one of the above categories.

For all plant costs classified as (1) “All ISO”, classify all such plant costs as Transmission Plant - ISO or Distribution Plant - ISO, as appropriate. For all plant costs classified as (2) “Non-ISO”, classify none of such plant costs as “Transmission Plant - ISO” or “Distribution Plant - ISO.”

For all plant costs classified as (3) “Mixed ISO and Non-ISO Substation,” perform an analysis of plant costs based on individual components of the substation. Component plant costs that are under the Operational Control of the ISO shall be attributed to either Transmission Plant - ISO or Distribution Plant - ISO, as appropriate. Component plant costs that are not under the Operational Control of the ISO shall not be attributed to either Transmission Plant - ISO or Distribution Plant - ISO. Dual Use assets (supporting both ISO and non-ISO plant) shall be allocated to Transmission Plant - ISO or Distribution Plant - ISO based on the percentage of ISO assets for the location.

For all plant costs classified as (4) “Mixed ISO and Non-ISO Line,” apply the methodology set forth in Section 9(c) below to classify such costs.

For all plant costs classified as (5) “Other” in a location, classify such costs as Transmission Plant - ISO or Distribution Plant - ISO in proportion to the total percentage of Transmission Plant - ISO or Distribution Plant - ISO determined in parts (1) through (4) for that location.

c) Transmission line costs (including any amounts in accounts 350, 352, and 353) required to be analyzed under the Transmission Line methodology pursuant to (b) (4) above shall be attributed to Transmission Plant - ISO according to the following methodology:

1) For each location, determine the total line miles and total line miles that are under the Operational Control of the ISO. Determine the percent of total line miles under the Operational Control of the ISO to total line miles at that location. This calculation shall be done separately for overhead and underground facilities in the location.

2) Determine the amount of Transmission Plant - ISO by applying the percent determined in (1) to the appropriate plant costs by account at that location.

SCE shall present a summary of the Plant Study for the Prior Year in each annual Draft Annual Update, in accordance with the Formula Rate.

10. DETERMINATION OF AMOUNT OF ISO OPERATION AND MAINTENANCE EXPENSE

SCE shall annually determine the amount of recorded Transmission and Distribution Operation and Maintenance ("O&M") expenses that is attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense"). The method used to determine ISO O&M Expense shall be to allocate total recorded O&M Expenses as stated in FERC Form 1 based on specific allocation factors applied to the expenses recorded to the O&M accounts set forth in Schedule 19 of the Formula Rate Spreadsheet.

In the event that SCE experiences an extraordinary event, resulting in costs otherwise recoverable through the Formula Rate in a year to be recorded to Account 435 (Extraordinary Deductions) of the Uniform System of Accounts, SCE shall recover the full amount of such Account 435 costs, including any expenses or return on capital, in accordance with the Commission Order authorizing such recovery.

11. RESERVATION OF RIGHTS

a) Nothing in these Protocols shall be deemed to limit in any way the right of any party admitted as an intervenor to this Formula Rate proceeding or admitted as an intervenor to any future proceeding involving an Annual Update to file a request for relief under any applicable provision of the FPA and/or the Commission's regulations or participate in Annual Update proceedings.

b) Nothing in these Protocols shall be deemed to limit in any way SCE's right to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, to seek to change or cancel the Formula Rate, or to submit any other request for relief under any applicable provision of the FPA and/or the Commission's regulations.

c) The party filing a proposed change to the Formula Rate Spreadsheet or Formula Rate Protocols under Section 205 or 206 of the FPA bears the standard burdens associated with such a filing.

12. USE OF INFORMATION

Information produced pursuant to these Protocols may be used in any proceeding concerning the Formula Rate Spreadsheet, the Protocols, or the Annual Update; provided, however, that to the extent that any information provided pursuant to these Protocols has been designated and provided as Protected Materials, subject to the provisions of Exhibit A to these Protocols, the use of such information shall be governed by Exhibit A.

This section shall not apply to any information produced in the course of Commission-established settlement proceedings pursuant to the Commission's rules and regulations governing settlement.

EXHIBIT A

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PROTECTIVE ORDER APPLICABLE TO INFORMATION PRODUCED BY SOUTHERN CALIFORNIA EDISON COMPANY PURSUANT TO THE FORMULA RATE PROTOCOLS

1. This Exhibit (hereinafter referred to as the "Protective Order") shall govern the use of all Protected Materials produced by, or on behalf of, Southern California Edison Company ("SCE") pursuant to the SCE Formula Rate Protocols.

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 CFR§ 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions -- For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 CFR § 385.102(b).

(b) (1) The term "Protected Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Administrative Law Judge appointed upon the Annual Update being set for hearing and/or settlement procedures or by the Discovery Master appointed pursuant to the Formula Rate Protocols (both referred to herein as the "Presiding Judge"), by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information B Do Not Release".

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the Service List, as defined in the SCE Formula Rate Protocols.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff;

(2) an attorney who has made an appearance for a Participant;

(3) attorneys, paralegals, and other employees associated with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in connection with the Annual Update for which the information was requested;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants with significant responsibility for SCE's Formula Rate.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the date that any Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 CFR § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to

Paragraph 9. Protected Materials shall not be used except as necessary under SCE's Formula Rate Protocols, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in working on SCE's Annual Update for which the information was requested and who needs to know the information in order to carry out such responsibilities. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained under SCE's Formula Rate Protocols to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in working on the Annual Update, as set forth above, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information - Do Not Release". For anything filed under seal, redacted versions or, where an entire

document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during a hearing under the SCE Formula Rate Protocols in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge finds at any time in the course of a proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory

appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 CFR §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. § 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced under the SCE Formula Rate Protocols under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order under the Southern California Edison Formula Rate Protocols, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________

Printed Name: _____________________

Title: ____________________________

Representing:______________________

Date: _____________________________

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	$ -
Incremental Forecast Period TRR	$ -
True-Up Adjustment	$ -
Cost Adjustment	$ -
Base TRR (retail)	$ -

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.

Schedule 1
Base TRR

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	Value
				-
RATE BASE				
1	ISO Transmission Plant		6-PlantInService, Line 19	$ -
2	General Plant + Electric Miscellaneous Intangible Plant		6-PlantInService, Line 27	$ -
3	Transmission Plant Held for Future Use		11-PHFU, Line 8	$ -
4	Abandoned Plant		12-AbandonedPlant, Line 3	$ -
	Working Capital amounts			
5	Materials and Supplies		13-WorkCap, Line 16	$ -
6	Prepayments		13-WorkCap, Line 36	$ -
7	Cash Working Capital		(Line 66 + Line 67) / 8	$ -
8	Working Capital		Line 5 + Line 6 + Line 7	$ -
	Accumulated Depreciation Reserve Balances			
9	Transmission Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 13, Col. 12	$ -
10	Distribution Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 16, Col. 5	$ -
11	General + Intangible Plant Depreciation Reserve	Negative amount	8-AccDep, Line 26	$ -
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	$ -
13	Accumulated Deferred Income Taxes	Negative amount	9-ADIT, Line 5, Col. 2	$ -
14	CWIP Plant		14-IncentivePlant, L 12, Col 1	$ -
15	Other Regulatory Assets/Liabilities		23-RegAssets, Line 14	$ -
16	Unfunded Reserves		34-UnfundedReserves, Line 6	$ -
17	Network Upgrade Credits	Negative amount	22-NUCs, Line 4	$ -
18	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L16 + L17	$ -
OTHER TAXES				
19	Sub-Total Local Taxes	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
20	Transmission Plant Allocation Factor		27-Allocators, Line 22	- %
21	Property Taxes		Line 19 * Line 20	$ -
22	Payroll Taxes Expense			
23	FICA		Line 24 + Line 25+ Line 26	$ -
24	Fed Ins Cont Amt -- Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
25	FICA/OASDI Emp Incntv.	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
26	FICA/HIT Emp Incntv.	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
27	CA SUI Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
28	Fed Unemp Tax Act- Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
29	CADI Vol Plan Assess	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
30	SF Pyrl Exp Tx - SCE	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$ -
31	Total Electric Payroll Tax Expense		Line 23 + (Line 27 to Line 30)	$ -
32	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 16	$ -
33	Remaining Electric Payroll Tax Expense to Allocate		Line 31 - Line 32	$ -
34	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9	- %
35	Payroll Taxes Expense		Line 33 * Line 34	$ -
36	Other Taxes	Note 1	Line 21 + Line 35	$ -

Schedule 1
Base TRR

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction		Value
RETURN AND CAPITALIZATION CALCULATIONS					
	Debt				
37	Long Term Debt Amount		5-ROR-1, Line 13	$	-
38	Cost of Long Term Debt		Line 37 * Line 39	$	-
39	Long Term Debt Cost Percentage		5-ROR-3, Line 12		- %
	Preferred Stock				
40	Preferred Stock Amount		5-ROR-1, Line 17	$	-
41	Cost of Preferred Stock		Line 40 * Line 42	$	-
42	Preferred Stock Cost Percentage		5-ROR-4, Line 9		- %
	Equity				
43	Common Stock Equity Amount		5-ROR-1, Line 23	$	-
44	Total Capital		Line 37 + Line 40 + Line 43	$	-
	Capital Percentages				
45	Long Term Debt Capital Percentage		Line 37 / Line 44		- %
46	Preferred Stock Capital Percentage		Line 40 / Line 44		- %
47	Common Stock Capital Percentage		Line 43 / Line 44		- %
			Line 45 + Line 46+ Line 47		- %
	Annual Cost of Capital Components				
48	Long Term Debt Cost Percentage		Line 39		- %
49	Preferred Stock Cost Percentage		Line 42		- %
50	Return on Common Equity	Note 2	SCE Return on Equity		17.62%
	Calculation of Cost of Capital Rate				
51	Weighted Cost of Long Term Debt		Line 39 * Line 45		- %
52	Weighted Cost of Preferred Stock		Line 42 * Line 46		- %
53	Weighted Cost of Common Stock		Line 47 * Line 50		- %
54	Cost of Capital Rate		Line 51 + Line 52 + Line 53		- %
55	Equity Rate of Return Including Common and Preferred Stock	Used for Tax calculation	Line 52 + Line 53		- %
56	Return on Capital: Rate Base times Cost of Capital Rate		Line 18 * Line 54	$	-
INCOME TAXES					
57	Federal Income Tax Rate		26-Tax Rates, Line 1		- %
58	State Income Tax Rate		26-Tax Rates, Line 8		- %
59	Composite Tax Rate	= F + [S * (1 - F)]	(L57 + L58) - (L57 * L58)		- %
	Calculation of Credits and Other:				
60	Amortization of Excess Deferred Tax Liability	Note 3		$	-
61	Investment Tax Credit Flowed Through	Note 3		$	-
62	South Georgia Income Tax Adjustment	Note 3			$2,606,000
63	Credits and Other		Line 60 + Line 61+ Line 62	$	-
64	Income Taxes:		Formula on Line 65	$	-
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	$	-

Schedule 1
Base TRR

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	Value	
					-
	PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT				
	Component of Prior Year TRR:				
66	O&M Expense		19-OandM, Line 91, Col. 6	$	-
67	A&G Expense		20-AandG, Line 23	$	-
68	Network Upgrade Interest Expense		22-NUCs, Line 8	$	-
69	Depreciation Expense		17-Depreciation, Line 70	$	-
70	Abandoned Plant Amortization Expense		12-AbandonedPlant, Line 1	$	-
71	Other Taxes		Line 36	$	-
72	Revenue Credits	Negative amount	21-Revenue Credits, Line 44	$	-
73	Return on Capital		Line 56	$	-
74	Income Taxes		Line 64	$	-
75	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	11-PHFU, Line 10	$	-
76	Amortization and Regulatory Debits/Credits		23-RegAssets, Line 16	$	-
77	Prior Year Incentive Adder		15-IncentiveAdder, Line 14	$	-
78	Total without FF&U		Sum of Lines 66 to 77	$	-
79	Franchise Fees Expense		L 78 * FF Factor (28-FFU, L 5)	$	-
80	Uncollectibles Expense		L 78 * U Factor (28-FFU, L 5)	$	-
81	Prior Year TRR		Line 78 + Line 79+ Line 80	$	-
	TOTAL BASE TRANSMISSION REVENUE REQUIREMENT				
	Calculation of Base Transmission Revenue Requirement				
82	Prior Year TRR		Line 81	$	-
83	Incremental Forecast Period TRR		2-IFPTRR, Line 82	$	-
84	True Up Adjustment		3-TrueUpAdjust, Line 30	$	-
85	Cost Adjustment	Note 4		$	-
86	Base Transmission Revenue Requirement (Retail)	For Retail Purposes	L 82 + L 83 + L 84 + L 85	$	-
	Wholesale Base Transmission Revenue Requirement				
87	Base TRR (Retail)		Line 86	$	-
88	Wholesale Difference to the Base TRR		25-WholesaleDifference, Line 45	$	-
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$	-

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 the South Georgia Income Tax Adjustment "Credits and Other" term 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.

Schedule 2
Incremental Forecast Period TRR

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-BaseTRR, Line 51
13	Wtd. Cost of Common + Pref. Stock:		- %	1-BaseTRR, Line 55
14	Composite Tax Rate:		- %	1-BaseTRR, Line 59
15				
16	AFCRCWIP =		- %	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:	$	-	6-PlantInService, Line 13
28	Distribution Plant - ISO:	$	-	6-PlantInService, Line 16
29	Transmission Dep. Reserve - ISO:	$	-	8-AccDep, Line 13
30	Distribution Dep. Reserve - ISO:	$	-	8-AccDep, Line 16
31	Net Plant:	$	-	(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:	$	-	10-CWIP, L 13 C1
38	AFCRCWIP:		- %	Line 16
39	Direct CWIP Related Costs:	$	-	Line 37 * Line 38
40				
41	**2) CWIP ROE Adder costs:**			
42	IREF:	$	-	15-IncentiveAdder, Line 3
43				
44	Tehachapi CWIP Amount:	$	-	10-CWIP, Line 13
45	Tehachapi ROE Adder %:		- %	15-IncentiveAdder, Line 5
46	Tehachapi ROE Adder $:	$	-	Formula on Line 52
47				
48	DCR CWIP Amount:	$	-	10-CWIP, Line 13
49	DCR ROE Adder %:		- %	15-IncentiveAdder, Line 6
50	DCR ROE Adder $:	$	-	Formula on Line 52
51				
52	ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)			
53				
54	CWIP Related Costs wo FF&U:	$	-	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	$	-	(28-FFU, L5 FF Factor + U Factor) * L54
56	CWIP Related Costs with FF&U:	$	-	Line 54 + Line 55
57				

Schedule 2
Incremental Forecast Period TRR

				Reference
58	**b) Determination of AFCR:**			
59				
60	CWIP Related Costs wo FF&U:	$	-	Line 54
61	Prior Year TRR wo FF&U:	$	-	1-BaseTRR, Line 78
62	Prior Year TRR wo CWIP Related Costs:	$	-	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	$	-	(1-BaseTRR, Line 66 + Line 67) * .75
64	AFCR:		- %	(Line 62 - Line 63) / Line 31
65				
66	**2) Calculation of IFP TRR**			
67				
68				**Reference**
69	Forecast Plant Additions:	$	-	16-PlantAdditions, L 25, C10
70	AFCR:		- %	Line 64
71	AFCR * Forecast Plant Additions:	$	-	Line 69 * Line 70
72				
73	Forecast Period Incremental CWIP:	$	-	10-CWIP, L 54, C8
74	AFCRCWIP:		- %	Line 16
75	AFCRCWIP * FP Incremental CWIP:	$	-	Line 73 * Line 74
76				
77	IFPTRR without FF&U:	$	-	Line 71 + Line 75
78				
79	Franchise Fees Expense:	$	-	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	$	-	Line 77 * U (from 28-FFU, L 5)
81				
82	Incremental Forecast Period TRR:	$	-	Line 77 + Line 79 + Line 80

Schedule 3
True Up Adjustment

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:	$ -	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
5–10	Month	Year	Monthly True Up TRR	Actual Retail Base Transmission Revenues	One-Time Adjustments and Shortfall/Excess Revenue In Previous Annual Update	Monthly Excess (-) or Shortfall (+) in Revenue	Monthly Interest Rate	Cumulative Excess (-) or Shortfall (+) in Revenue wo Interest for Current Month	Interest for Current Month	Cumulative Excess (-) or Shortfall (+) in Revenue with Interest
11	December	-	---	---	$ -	$ -	---	$ -	---	$ -
12	January	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
13	February	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
14	March	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
15	April	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
16	May	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
17	June	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
18	July	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
19	August	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
20	September	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
21	October	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
22	November	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
23	December	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -

24 **3) True Up Adjustment**

Line			Notes:
25			
26	Shortfall or Excess Revenue in Prior Year:	$ -	Line 23, Column 9
27	Previous Annual Update TU Adjustment:	$ -	Previous Annual Update Schedule 3, Line 30 — Previous Annual Update:
28	TU Adjustment without Projected Interest	$ -	Line 26 - Line 27
29	Projected Interest to Rate Year Mid-Point:	$ -	Line 28 * (Line 23, Column 6) * 18 months
30	True Up Adjustment:	$ -	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 **4) 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	Feb	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	Mar	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Apr	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	May	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	Jun	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	Jul	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Aug	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Sep	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Oct	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Nov	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Dec	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	Totals:	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76								
77		"Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b:						$ -

Schedule 3
True Up Adjustment

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.

<u>Notes:</u>

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.

Schedule 4
True Up TRR

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	$	-
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		6-PlantInService, Line 24	$	-
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		11-PHFU, Line 9	$	-
4	Abandoned Plant	BOY/EOY Avg.		12-AbandonedPlant Line 4	$	-
	Working Capital Amounts					
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	$	-
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	$	-
7	Cash Working Capital	1/8 (O&M + A&G)		1-Base TRR Line 7	$	-
8	Working Capital			Line 5 + Line 6 + Line 7	$	-
	Accumulated Depreciation Reserve Amounts					
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	8-AccDep, Line 14, Col. 12	$	-
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	8-AccDep, Line 17, Col. 5	$	-
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	8-AccDep, Line 23	$	-
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	$	-
13	Accumulated Deferred Income Taxes	Prorata BOY/EOY Avg.		9-ADIT, Line 15	$	-
14	CWIP Plant	13-Month Avg.		14-IncentivePlant, L 12, C2	$	-
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	22-NUCs, Line 7	$	-
16	Unfunded Reserves			34-UnfundedReserves, Line 7	$	-
17	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		23-RegAssets, Line 15	$	-
18	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L16+L17	$	-

B) Return on Capital

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

C) Income Taxes

21	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			$	-
	Where:				
22	RB = Rate Base		Line 18	$	-
23	ER = Equity ROR inc. Com. and Pref. Stock	Instruction 1	Instruction 1, Line k		- %
24	CTR = Composite Tax Rate		1-Base TRR L 59		- %
25	CO = Credits and Other		1-Base TRR L 63	$	-
26	D = Book Depreciation of AFUDC Equity Book Basis		1-Base TRR L 65	$	-

Schedule 4
True Up TRR

D) True Up TRR Calculation

27	O&M Expense	1-Base TRR L 66	$	-
28	A&G Expense	1-Base TRR L 67	$	-
29	Network Upgrade Interest Expense	1-Base TRR L 68	$	-
30	Depreciation Expense	1-Base TRR L 69	$	-
31	Abandoned Plant Amortization Expense	1-Base TRR L 70	$	-
32	Other Taxes	1-Base TRR L 71	$	-
33	Revenue Credits	1-Base TRR L 72	$	-
34	Return on Capital	Line 20	$	-
35	Income Taxes	Line 21	$	-
36	Gains and Losses on Transmission Plant Held for Future Use -- Land	1-Base TRR L 75	$	-
37	Amortization and Regulatory Debits/Credits	1-Base TRR L 76	$	-
38	Total without True Up Incentive Adder	Sum Line 27 to Line 37	$	-
39	True Up Incentive Adder	15-IncentiveAdder L 20	$	-
40	True Up TRR without Franchise Fees and Uncollectibles Expense included:	Line 38 + Line 39	$	-

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

Line				Reference:
41	True Up TRR wo FF:	$	-	Line 40
42	Franchise Fee Factor:		- %	28-FFU, L 5
43	Franchise Fee Expense:	$	-	Line 41 * Line 42
44	Uncollectibles Expense Factor:		- %	28-FFU, L 5
45	Uncollectibles Expense:	$	-	Line 41 * Line 44
46	True Up TRR:	$	-	L 41 + L 43 + L 45

Schedule 4
True Up TRR

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	- %	See Line e below	---	---	---
b	ROE start of Prior Year	- %	See Line f below	---	---	---
c					Total days in year:	____
d	Wtd. Avg. ROE in Prior Year	- %	((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	---
f	Beginning of Prior Year	---

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

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

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

Schedule 5 ROR-1
Return and Capitalization

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	Value
	RETURN AND CAPITALIZATION CALCULATIONS			-
	Calculation of Long Term Debt Amount			
1	Bonds -- Account 221	13-month avg.	5-ROR-2, Line 1	$ -
2	Less Reacquired Bonds -- Account 222	13-month avg.	5-ROR-2, Line 2	$ -
3	Long Term Debt Advances from Associated Companies -- Account 223	13-month avg.	5-ROR-2, Line 3	$ -
4	Other Long Term Debt -- Account 224	13-month avg.	5-ROR-2, Line 4	$ -
5	Unamortized Premium on Long Term Debt - Account 225	13-month avg.	5-ROR-2, Line 5	$ -
6	Less Unamortized Discount on Long Term Debt -- Account 226	13-month avg.; enter negative	5-ROR-2, Line 6	$ -
7	Unamortized Debt Expenses -- Account 181	13-month avg.; enter negative	5-ROR-2, Line 7	$ -
8	Unamortized Loss on Reacquired Debt -- Account 189	13-month avg.; enter negative	5-ROR-2, Line 8	$ -
9	Composite Tax Rate		1-BaseTRR, Line 59	- %
10	After tax amount of Unamortized Loss on Reacquired Debt		Line 8 * (1- Line 9)	$ -
11	Removal of Long Term Debt Related to Fuel Inventories	13-month avg.; enter negative	5-ROR-2, Line 9	$ -
12	Adjustments related to "LT Debt Related to Fuel Inventories"		5-ROR-2, Line 10	$ -
13	Long Term Debt Amount		Sum of Lines 1 to 7 and 10 to 12	$ -
	Calculation of Preferred Stock Amount			
14	Preferred Stock Amount -- Account 204	13-month avg.	5-ROR-2, Line 11	$ -
15	Unamortized Issuance Costs	13-month avg.	5-ROR-2, Line 12	$ -
16	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	5-ROR-2, Line 13	$ -
17	Preferred Stock Amount		Sum of Lines 14 to 16	$ -
	Calculation of Common Stock Equity Amount			
18	Total Proprietary Capital	13-month avg.	5-ROR-2, Lines 14 + 14a	$ -
19	Less Preferred Stock Amount -- Account 204	Same as L 14, but negative	5-ROR-2, Line 11	$ -
20	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 16, but reverse sign	5-ROR-2, Line 13	$ -
21	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.	5-ROR-2, Line 15	$ -
22	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg.	5-ROR-2, Line 16	$ -
23	Common Stock Equity Amount		Sum of Lines 18 to 22	$ -

Schedule 5 ROR-2
Return and Capitalization

Calculation of 13-Month Average Capitalization Balances

Year

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
1	**Bonds -- Account 221 (Note 1):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	**Reacquired Bonds -- Account 222 (Note 2): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	**Long Term Debt Advances from Associated Companies (Note 3):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	**Other Long Term Debt -- Account 224 (Note 4):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	**Unamortized Premium on Long Term Debt -- Account 225 (Note 5)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	**Less Unamortized Discount on Long Term Debt -- Account 226 (Note 6): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	**Unamortized Debt Expenses -- Account 181 (Note 7): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	**Unamortized Loss on Reacquired Debt -- Account 189 (Note 8): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	**Removal of Long Term Debt Not Financing Rate Base (Note 9)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Adjustments related to "LT Debt Not Financing Rate Base" (Note 10)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	**Preferred Stock Amount -- Account 204 (Note 11):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	**Unamortized Issuance Costs (Note 12)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	**Net Gain (Loss) From Purchase and Tender Offers (Note 13):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	**Total Proprietary Capital (Note 14):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14a	**Proprietary Capital Adjustment for Wildfire Related Capital**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	**Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 15): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	**Accumulated Other Comprehensive Loss -- Account 219 (Note 16): enter - of FF1**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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 112.22d, amount in Column 14 from FF1 112.22c, amounts in columns 3-13 from SCE internal records.
6) Amount in Column 2 from FF1 112.23d, amount in Column 14 from FF1 112.23c, amounts in columns 3-13 from SCE internal records.
7) Amount in Column 2 from FF1 111.69d, amount in Column 14 from FF1 111.69c, amounts in columns 3-13 from SCE internal records.
8) Amount in Column 2 from FF1 111.81d, amount in Column 14 from FF1 111.81c, 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 112.16d, amount in Column 14 from FF1 112.16c, amounts in columns 3-13 from SCE internal records.
14a) Represents Capital disclosed by SCE related to Wildfire Related Capital, not yet paid on a cash basis. Amounts in Columns 2-14 are from SCE internal records
15) Amount in Column 2 from FF1 112.12d, amount in Column 14 from FF1 112.12c, amounts in columns 3-13 from SCE internal records.
16) Amount in Column 2 from FF1 112.15d, amount in Column 14 from FF1 112.15c, amounts in columns 3-13 from SCE internal records.

Long Term Debt Cost Percentage

Prior Year:

1) Calculation of "Long Term Debt Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Outstanding Series Debt:	$ -	Line 200, Col 10
2	Total Annual Amortized Loss on Reacquired Debt:	$ -	FF1 117.64c
3	Total Annual Cost of Debt:	$ -	= L1 + L2
4			
5	Total "Principal Amount Outstanding" Debt:	$ -	Line 200, Col 5
6	Total Reacquired Debt:	$ -	Line 205, Col 5
7	Total Unamortized Loss on Reacquired Debt:	$ -	5-ROR-2, Line 8, Col. 14 (Negative of FF1 111.81c)
8	Composite Tax Rate:	- %	1-BaseTRR, Line 59
9	After-Tax Total Unamortized Loss on Reacquired Debt:	$ -	= L7 * (1 - L8)
10	Total Debt Balance:	$ -	= L5 + L6 + L9
11			
12	Long Term Debt Cost Percentage:	- %	= L3 / L10

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 257, Col h	Note 1	FF1 256, Col c Note 2	= Col 5 - Col 7	Note 3	= Col 5 * Col 9	
Line	**Series**	**Date of Offering**	**Maturity Date**	**Coupon Rate**	**Principal Amount Oustanding ($000s)**	**Amort-ization Period (Years)**	**Net Discount & Issuance Cost ($000s)**	**Net Proceeds ($000s)**	**Cost of Money**	**Annual Cost ($000s)**	**Comments: See below**
101						---	$ -	$ -	- %	$ -	
102						---	$ -	$ -	- %	$ -	
103						---	$ -	$ -	- %	$ -	
104						---	$ -	$ -	- %	$ -	
105						---	$ -	$ -	- %	$ -	
106						---	$ -	$ -	- %	$ -	
107						---	$ -	$ -	- %	$ -	
108						---	$ -	$ -	- %	$ -	
109						---	$ -	$ -	- %	$ -	
110						---	$ -	$ -	- %	$ -	
111						---	$ -	$ -	- %	$ -	
112						---	$ -	$ -	- %	$ -	
113						---	$ -	$ -	- %	$ -	
114						---	$ -	$ -	- %	$ -	
115						---	$ -	$ -	- %	$ -	
116						---	$ -	$ -	- %	$ -	
117						---	$ -	$ -	- %	$ -	
118						---	$ -	$ -	- %	$ -	
119						---	$ -	$ -	- %	$ -	
120						---	$ -	$ -	- %	$ -	
121						---	$ -	$ -	- %	$ -	
122						---	$ -	$ -	- %	$ -	
123						---	$ -	$ -	- %	$ -	
124						---	$ -	$ -	- %	$ -	
125						---	$ -	$ -	- %	$ -	
126						---	$ -	$ -	- %	$ -	
127						---	$ -	$ -	- %	$ -	
128						---	$ -	$ -	- %	$ -	
129						---	$ -	$ -	- %	$ -	
130						---	$ -	$ -	- %	$ -	
131						---	$ -	$ -	- %	$ -	
132						---	$ -	$ -	- %	$ -	
133	…										

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

Comment #:	Comment
…	

200 **Total Principal Amount Outstanding (sum of above * 1,000):** $ - **Total Annual Cost (sum of above * 1,000):** $ -

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						
202						
203						
204	…					
205				**Total Principal Amount (sum of above * 1,000):**	$ -	

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

Comment #:	Comment

Notes:
1) Equal to maturity date less the date of offering year
2) Sum of all amounts for each issuance
3) 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money
4) Excludes debt, or portions thereof, that does not finance Rate Base

Preferred Stock Cost Percentage
Prior Year:

1) Calculation of "Preferred Stock Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Preferred Stock:	$ -	Line 112, Col 9
2	Total Reacquired Preferred Stock Cost:	$ -	Line 312, Col 6
3	Total Annual Cost of Preferred:	$ -	= L1 + L2
4			
5	Total Preferred Stock Amount Outstanding:	$ -	FF1 112.3c
6	Net Gain (Loss) from Purchase and Tender Offers:	$ -	Line 312, Col 4
7	Total Preferred Balance:	$ -	= L5 - L6
8			
9	Preferred Stock Cost Percentage:	- %	= 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 Note 1	= Col 4 * Col 8	
Line	**Preferred Stock**	**Issue Date**	**Dividend Rate**	**Face Value / Amount Outstanding ($000s)**	**Total Issuance Cost ($000s)**	**Net Proceeds at Issuance ($000s)**	**% of Face Value**	**Cost of Money / Effective Rate**	**Annualized Cost ($000s)**	**Notes**
101					$ -	$ -	- %	- %	$ -	
102					$ -	$ -	- %	- %	$ -	
103					$ -	$ -	- %	- %	$ -	
104					$ -	$ -	- %	- %	$ -	
105					$ -	$ -	- %	- %	$ -	
106					$ -	$ -	- %	- %	$ -	
107					$ -	$ -	- %	- %	$ -	
108					$ -	$ -	- %	- %	$ -	
109					$ -	$ -	- %	- %	$ -	
110					$ -	$ -	- %	- %	$ -	
111	…				$ -	$ -	- %	- %	$ -	
112						Total Annual Cost (sum of above * 1,000):			$ -	

3) Preferred Stock Issuance Cost Details for each Outstanding Series

	Col 1	Col 2	Col 3	Col 4
	Same list as in Section 2	SCE Records	SCE Records	
Line	**Preferred Stock**	**Total Issuance Cost ($000s)**	**Full Amortization Period**	**Notes**
201				
202				
203				
204				
205				
206				
207				
208				
209				
210				
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 ($000s)	Col 4 SCE Records Net Gain (Loss) from Purchase and Tender Offers ($000s)	Col 5 SCE Records Amortization Period	Col 6 Col 3 / Col 5 Issuance Amortization Cost ($000s)	Notes
301						$ -	
302						$ -	
303						$ -	
304						$ -	
305						$ -	
306						$ -	
307						$ -	
308						$ -	
309						$ -	
310						$ -	
311	…					$ -	
312	Total Annual Cost (sum of above * 1,000):			$ -		$ -	

Notes:

1) If issuance costs not fully amortized then the “Cost of Money Effective Rate” is the 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money.
If the issuance costs are fully amortized then the “Cost of Money Effective Rate” is equal to Column 3 / Column 7.

Schedule 6
Plant In Service

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: -

	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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	13-Mo. Avg:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
16	-	$ -	$ -	$ -	$ -
17	Average:	$ -	$ -	$ -	$ -

3) ISO Transmission Plant

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

Line		Amount	Source
18	Average value:	$ -	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value:	$ -	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	$ -	$ -	$ -	BOY amount from previous PY
21	December	FF1 207.99.g and 205.5g	$ -	$ -	$ -	End of year ("EOY") amount

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

Line	b) EOY G&I Plant	Amount	Source
25	EOY Value:	$ -	Line 21.
26	Transmission W&S Allocation Factor:	- %	27-Allocators, Line 9
27	General + Intangible Plant:	$ -	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 Total
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 6
Plant In Service

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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Sum C2 - C11 Total
41	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Sum C2 - C11 Total
54	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Sum C2 - C11 Total
67	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 6
Plant In Service

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
94	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
95	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
96	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
97	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
98	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
99	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
100	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
101	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
102	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
103	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
104	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %

7) 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

	350.1	350.2	352	353	354	355	356	357	358	359	Total
106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

	350.1	350.2	352	353	354	355	356	357	358	359	Total
107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

8) 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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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.

Schedule 7
Transmission Plant Study Summary

Transmission Plant Study Input cells are shaded yellow

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

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	**Substation**					
3	352	$ -	FF1 207.49g	$ -	- %	
4	353	$ -	FF1 207.50g	$ -	- %	
5	**Total Substation**	$ -	L 3 + L 4	$ -	- %	
6						
7	**Land**					
8	350	$ -	FF1 207.48g	$ -	- %	
9						
10	**Total Substation and Land**	$ -	L 5 + L 8	$ -	- %	
11						
12	**Lines**					
13	354	$ -	FF1 207.51g	$ -	- %	
14	355	$ -	FF1 207.52g	$ -	- %	
15	356	$ -	FF1 207.53g	$ -	- %	
16	357	$ -	FF1 207.54g	$ -	- %	
17	358	$ -	FF1 207.55g	$ -	- %	
18	359	$ -	FF1 207.56g	$ -	- %	
19	**Total Lines**	$ -	Sum L13 to L18	$ -	- %	
20						
21	**Total Transmission**	$ -	L 10 + L 19	$ -	- %	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	$ -	FF1 207.60g	$ -	- %	
25	**Structures:**					
26	361	$ -	FF1 207.61g	$ -	- %	
27	362	$ -	FF1 207.62g	$ -	- %	
28	**Total Structures**	$ -	L 26 + L 27	$ -	- %	
29						
30	**Total Distribution**	$ -	L 24 + L 28	$ -	- %	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".

Schedule 8
Accumulated Depreciation

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Prior Year: -

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
		FERC Account:										=Sum C2 to C11
Line	**Mo/YR**	**350.1**	**350.2**	**352**	**353**	**354**	**355**	**356**	**357**	**358**	**359**	**Total**
1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	13-Mo. Avg:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$0	Beginning of Year ("BOY") amount
16	-	$ -	$ -	$ -	$0	End of Year ("EOY") amount
17	BOY/EOY Average:	$ -	$ -	$ -	$0	Average of Line 15 and Line 16

Schedule 8
Accumulated Depreciation

3) General and Intangible Depreciation Reserve

	Col 1	Col 2	Col 3	Col 4	Col 5	
			=C4+C5			
			Total Gen. and Int. Depreciation Reserve	General Depreciation Reserve	Intangible Depreciation Reserve	
	Mo/YR					Source
18	-	BOY:	$ -	$ -	$ -	FF1 219.28c and 200.21c for previous year
19	-	EOY:	$ -	$ -	$ -	FF1 219.28c and 200.21c
20		BOY/EOY Average:	$ -			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:	$ -	Line 20
22	Transmission W&S Allocation Factor:	- %	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$ -	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

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

Schedule 8
Accumulated Depreciation

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
41	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
42	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
43	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
44	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
45	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
46	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
47	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
48	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
49	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
50	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
51	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

B) Total Depreciation Expense (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
53	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

C) Other Activity (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 8
Accumulated Depreciation

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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 and Net Excess Deferred Tax Liabilities

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

a) End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

Line	Account Col 1	Total Balance Col 2	Source
1	Account 190	$ -	Line 353, Col. 2
2	Account 282	$ -	Line 452, Col. 2
3	Account 283	$ -	Line 803, Col. 2
4	Net Excess/Deficient Deferred Tax Liability/Asset-2017 TCAJA	$ -	FF1 278, see Notes 4 and 5
5	Total Accumulated Deferred Income Taxes	$ -	Sum of Lines 1 to 4
6	and Net Excess Deferred Tax Liabilities		
7	**b) Beginning of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
8		**BOY**	
9		**Balance**	**Source**
10	Total Accumulated Deferred Income Taxes	$ -	Previous Year Informational Filing, Line 5, Col. 2
11			
12	**c) Prorata Average of Beginning and End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
13		**Average**	
14		**ADIT**	**Source**
15	Prorata Average Balance:	$ -	Line 817, Column 8

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	-	-	$ -	$ -	$ -	$ -	$ -	-
101	-	-	$ -	$ -	$ -	$ -	$ -	-
102	-	-	$ -	$ -	$ -	$ -	$ -	-
103	-	-	$ -	$ -	$ -	$ -	$ -	-
104	-	-	$ -	$ -	$ -	$ -	$ -	-
105	-	-	$ -	$ -	$ -	$ -	$ -	-
106	-	-	$ -	$ -	$ -	$ -	$ -	-
107	-	-	$ -	$ -	$ -	$ -	$ -	-
108	-	-	$ -	$ -	$ -	$ -	$ -	-
109	-	-	$ -	$ -	$ -	$ -	$ -	-
110	-	-	$ -	$ -	$ -	$ -	$ -	-
111	-	-	$ -	$ -	$ -	$ -	$ -	-
112	-	-	$ -	$ -	$ -	$ -	$ -	-
113	-	-	$ -	$ -	$ -	$ -	$ -	-
114	-	-	$ -	$ -	$ -	$ -	$ -	-
115	-	-	$ -	$ -	$ -	$ -	$ -	-
116	-	-	$ -	$ -	$ -	$ -	$ -	-
117	-	-	$ -	$ -	$ -	$ -	$ -	-
118	-	-	$ -	$ -	$ -	$ -	$ -	-
119	-	-	$ -	$ -	$ -	$ -	$ -	-
120	-	-	$ -	$ -	$ -	$ -	$ -	-
121	-	-	$ -	$ -	$ -	$ -	$ -	-
122	-	-	$ -	$ -	$ -	$ -	$ -	-
123	-	-	$ -	$ -	$ -	$ -	$ -	-
124	-	-	$ -	$ -	$ -	$ -	$ -	-
125	-	-	$ -	$ -	$ -	$ -	$ -	-
126	-	-	$ -	$ -	$ -	$ -	$ -	-
127	-	-	$ -	$ -	$ -	$ -	$ -	-
128	-	-	$ -	$ -	$ -	$ -	$ -	-
129	-	-	$ -	$ -	$ -	$ -	$ -	-
130	-	-	$ -	$ -	$ -	$ -	$ -	-
131	-	-	$ -	$ -	$ -	$ -	$ -	-
132	-	-	$ -	$ -	$ -	$ -	$ -	-
133	-	-	$ -	$ -	$ -	$ -	$ -	-
134	-	-	$ -	$ -	$ -	$ -	$ -	-
135	-	-	$ -	$ -	$ -	$ -	$ -	-
136	-	-	$ -	$ -	$ -	$ -	$ -	-
137	-	-	$ -	$ -	$ -	$ -	$ -	-
138	-	-	$ -	$ -	$ -	$ -	$ -	-
139	-	-	$ -	$ -	$ -	$ -	$ -	-
140	-	-	$ -	$ -	$ -	$ -	$ -	-
141	-	-	$ -	$ -	$ -	$ -	$ -	-

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:							
142	-	-	$ -	$ -	$ -	$ -	$ -	-
143	-	-	$ -	$ -	$ -	$ -	$ -	-
144	-	-	$ -	$ -	$ -	$ -	$ -	-
145	-	-	$ -	$ -	$ -	$ -	$ -	-
146	-	-	$ -	$ -	$ -	$ -	$ -	-
147	-	-	$ -	$ -	$ -	$ -	$ -	-
148	-	-	$ -	$ -	$ -	$ -	$ -	-
149	-	-	$ -	$ -	$ -	$ -	$ -	-
150	-	-	$ -	$ -	$ -	$ -	$ -	-
151	-	-	$ -	$ -	$ -	$ -	$ -	-
152	-	-	$ -	$ -	$ -	$ -	$ -	-
153	-	-	$ -	$ -	$ -	$ -	$ -	-
154	-	-	$ -	$ -	$ -	$ -	$ -	-
155	-	-	$ -	$ -	$ -	$ -	$ -	-
156	-	-	$ -	$ -	$ -	$ -	$ -	-
157	-	-	$ -	$ -	$ -	$ -	$ -	-
158	-	-	$ -	$ -	$ -	$ -	$ -	-
159	-	-	$ -	$ -	$ -	$ -	$ -	-
160	-	-	$ -	$ -	$ -	$ -	$ -	-
161	-	-	$ -	$ -	$ -	$ -	$ -	-
162	-	-	$ -	$ -	$ -	$ -	$ -	-
163	-	-	$ -	$ -	$ -	$ -	$ -	-
164	-	-	$ -	$ -	$ -	$ -	$ -	-
165	-	-	$ -	$ -	$ -	$ -	$ -	-
166	-	-	$ -	$ -	$ -	$ -	$ -	-
167	-	-	$ -	$ -	$ -	$ -	$ -	-
168	-	-	$ -	$ -	$ -	$ -	$ -	-
169	-	-	$ -	$ -	$ -	$ -	$ -	-
170	-	-	$ -	$ -	$ -	$ -	$ -	-
171	-	-	$ -	$ -	$ -	$ -	$ -	-
172	-	-	$ -	$ -	$ -	$ -	$ -	-
173	-	-	$ -	$ -	$ -	$ -	$ -	-
174	-	-	$ -	$ -	$ -	$ -	$ -	-
175	…							
								Source
250	Total Electric 190		$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 100

	Account 190 Gas and Other Income:	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
300	-	-	$ -	$ -	$ -	$ -	$ -	-
301	-	-	$ -	$ -	$ -	$ -	$ -	-
302	-	-	$ -	$ -	$ -	$ -	$ -	-
303	-	-	$ -	$ -	$ -	$ -	$ -	-
304	-	-	$ -	$ -	$ -	$ -	$ -	-
305	-	-	$ -	$ -	$ -	$ -	$ -	-
306	-	-	$ -	$ -	$ -	$ -	$ -	-
307	-	-	$ -	$ -	$ -	$ -	$ -	-
308	-	-	$ -	$ -	$ -	$ -	$ -	-
309	-	-	$ -	$ -	$ -	$ -	$ -	-
310	-	-	$ -	$ -	$ -	$ -	$ -	-
311	-	-	$ -	$ -	$ -	$ -	$ -	-
312	-	-	$ -	$ -	$ -	$ -	$ -	-
313	-	-	$ -	$ -	$ -	$ -	$ -	-
314	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
350	Total Account 190 Gas and Other Income	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 300
351	Total Account 190	$ -	$ -	$ -	$ -	$ -	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				- %	- %	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	$ -		$ -	$ -	$ -	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
354	FERC Form 1 Account 190	$ -	Must match amount on Line 351, Col. 2				FF1 234.18c

3) Account 282 Detail

	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	-	-	$ -	$ -	$ -	$ -	$ -	-
401	-	-	$ -	$ -	$ -	$ -	$ -	-
402	-	-	$ -	$ -	$ -	$ -	$ -	-
403	-	-	$ -	$ -	$ -	$ -	$ -	-
404	-	-	$ -	$ -	$ -	$ -	$ -	-
405	-	-	$ -	$ -	$ -	$ -	$ -	-
406	-	-	$ -	$ -	$ -	$ -	$ -	-
407	-	-	$ -	$ -	$ -	$ -	$ -	-
408	-	-	$ -	$ -	$ -	$ -	$ -	-
409	-	-	$ -	$ -	$ -	$ -	$ -	-
410	-	-	$ -	$ -	$ -	$ -	$ -	-
411	-	-	$ -	$ -	$ -	$ -	$ -	-
412	-	-	$ -	$ -	$ -	$ -	$ -	-
413	-	-	$ -	$ -	$ -	$ -	$ -	-
414	-	-	$ -	$ -	$ -	$ -	$ -	-
415	-	-	$ -	$ -	$ -	$ -	$ -	-
416	-	-	$ -	$ -	$ -	$ -	$ -	-
417	-	-	$ -	$ -	$ -	$ -	$ -	-
418	-	-	$ -	$ -	$ -	$ -	$ -	-
419	-	-	$ -	$ -	$ -	$ -	$ -	-
420	…							

		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
450	Total Account 282		$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)					- %	- %	27-Allocators Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)		$ -		$ -	$ -	$ -	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282		$ -	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	-	-	$ -	$ -	$ -	$ -	$ -	-
501	-	-	$ -	$ -	$ -	$ -	$ -	-
502	-	-	$ -	$ -	$ -	$ -	$ -	-
503	-	-	$ -	$ -	$ -	$ -	$ -	-
504	-	-	$ -	$ -	$ -	$ -	$ -	-
505	-	-	$ -	$ -	$ -	$ -	$ -	-
506	-	-	$ -	$ -	$ -	$ -	$ -	-
507	-	-	$ -	$ -	$ -	$ -	$ -	-
508	-	-	$ -	$ -	$ -	$ -	$ -	-
509	-	-	$ -	$ -	$ -	$ -	$ -	-
510	-	-	$ -	$ -	$ -	$ -	$ -	-
511	-	-	$ -	$ -	$ -	$ -	$ -	-
512	-	-	$ -	$ -	$ -	$ -	$ -	-
513	-	-	$ -	$ -	$ -	$ -	$ -	-
514	-	-	$ -	$ -	$ -	$ -	$ -	-
515	-	-	$ -	$ -	$ -	$ -	$ -	-
516	-	-	$ -	$ -	$ -	$ -	$ -	-
517	-	-	$ -	$ -	$ -	$ -	$ -	-
518	-	-	$ -	$ -	$ -	$ -	$ -	-
519	-	-	$ -	$ -	$ -	$ -	$ -	-
520	-	-	$ -	$ -	$ -	$ -	$ -	-
521	-	-	$ -	$ -	$ -	$ -	$ -	-
522	-	-	$ -	$ -	$ -	$ -	$ -	-
523	-	-	$ -	$ -	$ -	$ -	$ -	-
524	-	-	$ -	$ -	$ -	$ -	$ -	-
525	-	-	$ -	$ -	$ -	$ -	$ -	-
526	-	-	$ -	$ -	$ -	$ -	$ -	-
527	-	-	$ -	$ -	$ -	$ -	$ -	-
528	-	-	$ -	$ -	$ -	$ -	$ -	-
529	-	-	$ -	$ -	$ -	$ -	$ -	-
530	-	-	$ -	$ -	$ -	$ -	$ -	-
531	-	-	$ -	$ -	$ -	$ -	$ -	-
532	-	-	$ -	$ -	$ -	$ -	$ -	-
533	-	-	$ -	$ -	$ -	$ -	$ -	-
534	-	-	$ -	$ -	$ -	$ -	$ -	-
535	-	-	$ -	$ -	$ -	$ -	$ -	-
536	-	-	$ -	$ -	$ -	$ -	$ -	-
537	-	-	$ -	$ -	$ -	$ -	$ -	-
538	-	-	$ -	$ -	$ -	$ -	$ -	-
539	-	-	$ -	$ -	$ -	$ -	$ -	-

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):							
540	-	-	$ -	$ -	$ -	$ -	$ -	-
541	-	-	$ -	$ -	$ -	$ -	$ -	-
542	-	-	$ -	$ -	$ -	$ -	$ -	-
543	-	-	$ -	$ -	$ -	$ -	$ -	-
544	-	-	$ -	$ -	$ -	$ -	$ -	-
545	-	-	$ -	$ -	$ -	$ -	$ -	-
546	-	-	$ -	$ -	$ -	$ -	$ -	-
547	-	-	$ -	$ -	$ -	$ -	$ -	-
548	-	-	$ -	$ -	$ -	$ -	$ -	-
549	-	-	$ -	$ -	$ -	$ -	$ -	-
550	-	-	$ -	$ -	$ -	$ -	$ -	-
551	-	-	$ -	$ -	$ -	$ -	$ -	-
552	-	-	$ -	$ -	$ -	$ -	$ -	-
553	-	-	$ -	$ -	$ -	$ -	$ -	-
554	-	-	$ -	$ -	$ -	$ -	$ -	-
555	-	-	$ -	$ -	$ -	$ -	$ -	-
556	-	-	$ -	$ -	$ -	$ -	$ -	-
557	-	-	$ -	$ -	$ -	$ -	$ -	-
558	-	-	$ -	$ -	$ -	$ -	$ -	-
559	-	-	$ -	$ -	$ -	$ -	$ -	-
560	-	-	$ -	$ -	$ -	$ -	$ -	-
561	-	-	$ -	$ -	$ -	$ -	$ -	-
562	-	-	$ -	$ -	$ -	$ -	$ -	-
563	-	-	$ -	$ -	$ -	$ -	$ -	-
564	-	-	$ -	$ -	$ -	$ -	$ -	-
565	-	-	$ -	$ -	$ -	$ -	$ -	-
566	-	-	$ -	$ -	$ -	$ -	$ -	-
567	-	-	$ -	$ -	$ -	$ -	$ -	-
568	-	-	$ -	$ -	$ -	$ -	$ -	-
569	…							
650	Total Electric 283		$0	$0	$0	$0	$0	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	-	-	$ -	$ -	$ -	$ -	$ -	-
701	-	-	$ -	$ -	$ -	$ -	$ -	-
702	-	-	$ -	$ -	$ -	$ -	$ -	-
703	-	-	$ -	$ -	$ -	$ -	$ -	-
704	-	-	$ -	$ -	$ -	$ -	$ -	-
705	-	-	$ -	$ -	$ -	$ -	$ -	-
706	-	-	$ -	$ -	$ -	$ -	$ -	-
707	-	-	$ -	$ -	$ -	$ -	$ -	-
708	-	-	$ -	$ -	$ -	$ -	$ -	-
709	-	-	$ -	$ -	$ -	$ -	$ -	-
710	-	-	$ -	$ -	$ -	$ -	$ -	-
711	-	-	$ -	$ -	$ -	$ -	$ -	-
712	-	-	$ -	$ -	$ -	$ -	$ -	-
713	…							

Schedule 9
ADIT

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
800	Total Account 283 Gas and Other	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 700
801	Total Account 283	$ -	$ -	$ -	$ -	$ -	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				- %	- %	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	$ -		$ -	$ -	$ -	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	$ -	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)

	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
		Mthly Deferred	Deferred		Number of Days	Prorata	Monthly	Annual Accumulated
	Future Test Period	Tax Amount	Tax Balance	Days in Month	Left in Period	Percentages	Prorata Amounts	Prorata Calculation
805	Beginning Deferred Tax Balance (Line 10, Col. 2)		$ -		-	- %		$ -
806	January	$ -	$ -	-	-	- %	$ -	$ -
807	February	$ -	$ -	-	-	- %	$ -	$ -
808	March	$ -	$ -	-	-	- %	$ -	$ -
809	April	$ -	$ -	-	-	- %	$ -	$ -
810	May	$ -	$ -	-	-	- %	$ -	$ -
811	June	$ -	$ -	-	-	- %	$ -	$ -
812	July	$ -	$ -	-	-	- %	$ -	$ -
813	August	$ -	$ -	-	-	- %	$ -	$ -
814	September	$ -	$ -	-	-	- %	$ -	$ -
815	October	$ -	$ -	-	-	- %	$ -	$ -
816	November	$ -	$ -	-	-	- %	$ -	$ -
817	December	$ -	$ -	-	-	- %	$ -	$ -
818	Ending Balance (Line 5, Col. 2)		$ -					

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	$ -
B:Gas Wages and Salaries	FF1 355.62b	$ -
C:Water Wages and Salaries	FF1 355.64b	$ -
D:Total Electric, Gas, and Water Wages and Salaries	A+B+C	$ -
E:Labor Percentage "Gas, Generation, or Other"	(B+C) / D	- %

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	$ -
G:Total Gas Plant In Service	FF1 201.8d	$ -
H:Total Water Plant in Service	FF1 201.8e	$ -
I:Total Electric, Gas, and Water Plant In Service	F+G+H	$ -
J:Plant Percentage "Gas, Generation, or Other"	(G+H) / I	- %

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 Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities balance minus the beginning Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities balance, divided by 12 months.
2) For January through December = previous month balance plus amount in Column 2.
3) The average Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities Balance is equal to the amount on Line 817, Column 8. Line 805 is equal to Line 10, Column 2. Lines 806 through 817 equal previous amount in Column 8, plus amount in Column 7.
4) The net excess/deficiency is derived from the deficiency arising in Account 190 offset by excesses in Accounts 282 and 283.
5) SCE must submit a Federal Power Act Section 205 filing to obtain Commission approval prior to reflecting in rates any regulatory assets and liabilities arising from future tax changes.

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

Line	Month	Year	Col 1 = Sum of all columns Monthly Total CWIP	Col 2 Tehachapi	Col 3 Devers to Colorado River	Col 4 South of Kramer	Col 5 West of Devers	Col 6 Red Bluff
1	December	-	$ -	$ -	$ -	$ -	$ -	$ -
2	January	-	$ -	$ -	$ -	$ -	$ -	$ -
3	February	-	$ -	$ -	$ -	$ -	$ -	$ -
4	March	-	$ -	$ -	$ -	$ -	$ -	$ -
5	April	-	$ -	$ -	$ -	$ -	$ -	$ -
6	May	-	$ -	$ -	$ -	$ -	$ -	$ -
7	June	-	$ -	$ -	$ -	$ -	$ -	$ -
8	July	-	$ -	$ -	$ -	$ -	$ -	$ -
9	August	-	$ -	$ -	$ -	$ -	$ -	$ -
10	September	-	$ -	$ -	$ -	$ -	$ -	$ -
11	October	-	$ -	$ -	$ -	$ -	$ -	$ -
12	November	-	$ -	$ -	$ -	$ -	$ -	$ -
13	December	-	$ -	$ -	$ -	$ -	$ -	$ -
14	13 Month Averages:		$ -	$ -	$ -	$ -	$ -	$ -

Line	Month	Year	Col 7 Whirlwind Substation Expansion	Col 8 Colorado River Substation Expansion	Col 9	Col 10	Col 11	Col 12
15	December	-	$ -	$ -	$ -	$ -	---	---
16	January	-	$ -	$ -	$ -	$ -	---	---
17	February	-	$ -	$ -	$ -	$ -	---	---
18	March	-	$ -	$ -	$ -	$ -	---	---
19	April	-	$ -	$ -	$ -	$ -	---	---
20	May	-	$ -	$ -	$ -	$ -	---	---
21	June	-	$ -	$ -	$ -	$ -	---	---
22	July	-	$ -	$ -	$ -	$ -	---	---
23	August	-	$ -	$ -	$ -	$ -	---	---
24	September	-	$ -	$ -	$ -	$ -	---	---
25	October	-	$ -	$ -	$ -	$ -	---	---
26	November	-	$ -	$ -	$ -	$ -	---	---
27	December	-	$ -	$ -	$ -	$ -	---	---
28	13 Month Averages:		$ -	$ -	$ -	$ -	$ -	$ -

Schedule 10
CWIP

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	-	---	---	---	---	---	---	$ -	---
30	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	**13-Month Averages:**									**$ -**

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	-	---	---	---	---	---	---	$ -	---
56	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80	**13-Month Averages:**									**$ -**

Schedule 10
CWIP

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	-	---	---	---	---	---	---	$0	---
82	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106	13-Month Averages:									$ -

3c) Project: South of Kramer

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
107	December	-	---	---	---	---	---	---	$0	---
108	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
128	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
129	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132	13-Month Averages:									$ -

3d) Project: West of Devers

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	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
133	December	-	---	---	---	---	---	---	$0	---
134	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
135	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
139	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
140	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
144	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
145	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
150	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
155	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
156	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158	**13-Month Averages:**									**$ -**

3e) Project: Red Bluff

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	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
159	December	-	---	---	---	---	---	---	$0	---
160	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
161	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
164	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
165	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
166	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
170	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
171	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
174	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
176	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
181	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
182	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184	**13-Month Averages:**									**$ -**

Schedule 10
CWIP

3f) Project: Whirlwind Substation Expansion

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 Unload 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
185	December	-	---	---	---	---	---	---	$0	---
186	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
187	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
190	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
191	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
192	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
193	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
195	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
197	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
198	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
208	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
210	13-Month Averages:									$ -

3g) Project: Colorado River Substation Expansion

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
211	December	-	---	---	---	---	---	---	$0	---
212	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
213	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
218	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
220	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
222	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
223	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
224	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
225	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
226	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
227	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
228	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
229	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
230	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
231	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
233	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
234	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
235	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236	13-Month Averages:									$ -

Schedule 10
CWIP

3h) Project:

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
237	December	-	---	---	---	---	---	---	$0	---
238	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
239	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
242	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
243	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
245	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
247	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
248	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
251	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
253	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
257	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
258	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
259	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
260	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
261	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
262	**13-Month Averages:**									**$ -**

3i) Project:

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
263	December	-	---	---	---	---	---	---	$0	---
264	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
265	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
267	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
268	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
269	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
272	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
273	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
280	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
281	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
282	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
283	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
285	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
288	**13-Month Averages:**									**$ -**

Schedule 10
CWIP

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

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
289	December	-	---	---	---	---	---	---	$0	---
290	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
291	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
292	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
293	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
294	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
295	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
296	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
297	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
298	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
299	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
300	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
301	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
302	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
303	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
304	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
305	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
306	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
307	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
308	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
309	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
310	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
312	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
313	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
314	**13-Month Averages:**									**$ -**

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.

Schedule 11
Plant Held for Future Use

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	$ -	$ -	FF1 page 214.47d

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

	Col 1	Col 2	Col 3	Col 4	Col 5
	Description	Type of Plant	Beginning of Year Balance	End of Year Balance	Source
2a			$ -	$ -	
2b			$ -	$ -	
2c			$ -	$ -	
2d			$ -	$ -	
2e			$ -	$ -	
2f			$ -	$ -	
2g			$ -	$ -	
2h			$ -	$ -	
	...				
3		Total:	$ -	$ -	Sum of above lines

		Beginning of Year Balance	End of Year Balance	Source
4	General Plant Held for Future Use	$ -	$ -	FF1 page 214
5	Wages and Salaries AF:	- %	- %	27-Allocators, L 9
6	Portion for Transmission PHFU:	$ -	$ -	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		$ -	$ -	Note 1

		Beginning of Year Balance	End of Year Balance	Source
8	Transmission PHFU:	$ -	$ -	L 3 + L 6
9	Average of BOY and EOY Transmission PHFU:	$ -		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	$ -	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.

Schedule 12
Abandoned Plant

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:	---	---
	---	---
	…	…

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:	$ -	Sum of projects below for PY.
2	Abandoned Plant (BOY):	$ -	Sum of projects below for PY.
3	Abandoned Plant (EOY):	$ -	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	$ -	Average of Lines 2 and 3.
5	HV Abandoned Plant (BOY):	$ -	Sum of projects below for PY.

6	First Project: Fill in Name			2nd Project: Fill in Name		
Line	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	$ -	$ -	$ -	$ -	$ -	$ -
8	2016	$ -	$ -	$ -	$ -	$ -	$ -
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.

Schedule 13
Working Capital

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	-	FF1 227.12b	$ -	Beginning of year ("BOY") amount
2	January	-	SCE Records	$ -	
3	February	-	SCE Records	$ -	
4	March	-	SCE Records	$ -	
5	April	-	SCE Records	$ -	
6	May	-	SCE Records	$ -	
7	June	-	SCE Records	$ -	
8	July	-	SCE Records	$ -	
9	August	-	SCE Records	$ -	
10	September	-	SCE Records	$ -	
11	October	-	SCE Records	$ -	
12	November	-	SCE Records	$ -	
13	December	-	FF1 227.12c	$ -	End of Year ("EOY") amount
14			13-Month Average Value Account 154:	$ -	(Sum Line 1 to Line 13) / 13
15			Transmission Wages and Salaries AF:	- %	27-Allocators, Line 9
16	**Materials and Supplies**		EOY Value:	$ -	Line 13 * Line 15
17			13-Month Average Value:	$ -	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.

	Month	Year	Data Source	Total Prepayments Balances	Notes
18	December	-	Note 1, c	$ -	See Note 1, c
19	January	-	SCE Records	$ -	
20	February	-	SCE Records	$ -	
21	March	-	SCE Records	$ -	
22	April	-	SCE Records	$ -	
23	May	-	SCE Records	$ -	
24	June	-	SCE Records	$ -	
25	July	-	SCE Records	$ -	
26	August	-	SCE Records	$ -	
27	September	-	SCE Records	$ -	
28	October	-	SCE Records	$ -	
29	November	-	SCE Records	$ -	
30	December	-	Note 1, f	$ -	See Note 1, f
	a) 13-Month Average Calculation				
31			13-Month Average Value:	$ -	(Sum Line 18 to Line 30) / 13
32			Transmission Wages and Salaries AF:	- %	27-Allocators, Line 9
33			Prepayments:	$ -	Line 31 * Line 32
	b) EOY calculation				
34			EOY Value:	$ -	Line 30
35			Transmission Wages and Salaries AF:	- %	27-Allocators, Line 9
36			Prepayments:	$ -	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:	$ -	FF1 111.57d
b	Prior Period Adjustment:	$ -	Note 1
c	BOY Prepayments Amount:	$ -	a - b

	End of Year Amount	Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	$ -	FF1 111.57c
e	Prior Period Adjustment:	$ -	Note 1
f	EOY Prepayments Amount:	$ -	d - e

Schedule 14
Incentive Plant

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	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 80
2	2) Devers-Colorado River	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 106
3	3) South of Kramer	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 132
4	4) West of Devers	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 158
5	5) Red Bluff	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 184
6	6) Whirlwind Substation Exp.	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 210
7	7) Colorado River Sub. Exp.	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 236
8	8)	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 262
9	9)	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 288
10	…				…
11					
12	Totals:	$ -	$ -	$ -	

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	$ -	$ -	$ -	Line 37, C4
14	2) Tehachapi	$ -	$ -	$ -	Line 1, C1, and Line 37, C2
15	3) Devers-Colorado River	$ -	$ -	$ -	Line 2, C1, and Line 37, C3
16	…				…
17					
18	Total PY Incentive Net Plant:	$ -			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	$ -	$ -	$ -	Line 38, C4
20	2) Tehachapi	$ -	$ -	$ -	Line 1, C2, and Line 38, C2
21	3) Devers-Colorado R	$ -	$ -	$ -	Line 2, C2, and Line 38, C3
22	…				…
23					
24	Total PY Incentive Net Plant:	$ -			13 Month Average

Schedule 14
Incentive Plant

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	-	$ -	$ -	$ -	$ -	---	←December of year previous to Prior Year
26	January	-	$ -	$ -	$ -	$ -	---	
27	February	-	$ -	$ -	$ -	$ -	---	
28	March	-	$ -	$ -	$ -	$ -	---	
29	April	-	$ -	$ -	$ -	$ -	---	
30	May	-	$ -	$ -	$ -	$ -	---	
31	June	-	$ -	$ -	$ -	$ -	---	
32	July	-	$ -	$ -	$ -	$ -	---	
33	August	-	$ -	$ -	$ -	$ -	---	
34	September	-	$ -	$ -	$ -	$ -	---	
35	October	-	$ -	$ -	$ -	$ -	---	
36	November	-	$ -	$ -	$ -	$ -	---	
37	December	-	$ -	$ -	$ -	$ -	---	
38		13 Month Averages:	$ -	$ -	$ -	$ -		

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	-	$ -	$ -	$ -	C1: Sum of below projects for each month
40	January	-	$ -	$ -	$ -	
41	February	-	$ -	$ -	$ -	
42	March	-	$ -	$ -	$ -	
43	April	-	$ -	$ -	$ -	
44	May	-	$ -	$ -	$ -	
45	June	-	$ -	$ -	$ -	
46	July	-	$ -	$ -	$ -	
47	August	-	$ -	$ -	$ -	
48	September	-	$ -	$ -	$ -	
49	October	-	$ -	$ -	$ -	
50	November	-	$ -	$ -	$ -	
51	December	-	$ -	$ -	$ -	
52	Total		$ -	$ -	$ -	

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	-	$ -	$ -	$ -	$ -
54	January	-	$ -	$ -	$ -	$ -
55	February	-	$ -	$ -	$ -	$ -
56	March	-	$ -	$ -	$ -	$ -
57	April	-	$ -	$ -	$ -	$ -
58	May	-	$ -	$ -	$ -	$ -
59	June	-	$ -	$ -	$ -	$ -
60	July	-	$ -	$ -	$ -	$ -
61	August	-	$ -	$ -	$ -	$ -
62	September	-	$ -	$ -	$ -	$ -
63	October	-	$ -	$ -	$ -	$ -
64	November	-	$ -	$ -	$ -	$ -
65	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

	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	-	$ -	$ -	$ -	$ -
67	January	-	$ -	$ -	$ -	$ -
68	February	-	$ -	$ -	$ -	$ -
69	March	-	$ -	$ -	$ -	$ -
70	April	-	$ -	$ -	$ -	$ -
71	May	-	$ -	$ -	$ -	$ -
72	June	-	$ -	$ -	$ -	$ -
73	July	-	$ -	$ -	$ -	$ -
74	August	-	$ -	$ -	$ -	$ -
75	September	-	$ -	$ -	$ -	$ -
76	October	-	$ -	$ -	$ -	$ -
77	November	-	$ -	$ -	$ -	$ -
78	December	-	$ -	$ -	$ -	$ -

	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	-	$ -	$ -	$ -	$ -
80	January	-	$ -	$ -	$ -	$ -
81	February	-	$ -	$ -	$ -	$ -
82	March	-	$ -	$ -	$ -	$ -
83	April	-	$ -	$ -	$ -	$ -
84	May	-	$ -	$ -	$ -	$ -
85	June	-	$ -	$ -	$ -	$ -
86	July	-	$ -	$ -	$ -	$ -
87	August	-	$ -	$ -	$ -	$ -
88	September	-	$ -	$ -	$ -	$ -
89	October	-	$ -	$ -	$ -	$ -
90	November	-	$ -	$ -	$ -	$ -
91	December	-	$ -	$ -	$ -	$ -

	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	-	$ -	$ -	$ -	$ -
93	January	-	$ -	$ -	$ -	$ -
94	February	-	$ -	$ -	$ -	$ -
95	March	-	$ -	$ -	$ -	$ -
96	April	-	$ -	$ -	$ -	$ -
97	May	-	$ -	$ -	$ -	$ -
98	June	-	$ -	$ -	$ -	$ -
99	July	-	$ -	$ -	$ -	$ -
100	August	-	$ -	$ -	$ -	$ -
101	September	-	$ -	$ -	$ -	$ -
102	October	-	$ -	$ -	$ -	$ -
103	November	-	$ -	$ -	$ -	$ -
104	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

e) West of Devers

	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
105	December	-	$ -	$ -	$ -	$ -
106	January	-	$ -	$ -	$ -	$ -
107	February	-	$ -	$ -	$ -	$ -
108	March	-	$ -	$ -	$ -	$ -
109	April	-	$ -	$ -	$ -	$ -
110	May	-	$ -	$ -	$ -	$ -
111	June	-	$ -	$ -	$ -	$ -
112	July	-	$ -	$ -	$ -	$ -
113	August	-	$ -	$ -	$ -	$ -
114	September	-	$ -	$ -	$ -	$ -
115	October	-	$ -	$ -	$ -	$ -
116	November	-	$ -	$ -	$ -	$ -
117	December	-	$ -	$ -	$ -	$ -

f) Red Bluff

	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
118	December	-	$ -	$ -	$ -	$ -
119	January	-	$ -	$ -	$ -	$ -
120	February	-	$ -	$ -	$ -	$ -
121	March	-	$ -	$ -	$ -	$ -
122	April	-	$ -	$ -	$ -	$ -
123	May	-	$ -	$ -	$ -	$ -
124	June	-	$ -	$ -	$ -	$ -
125	July	-	$ -	$ -	$ -	$ -
126	August	-	$ -	$ -	$ -	$ -
127	September	-	$ -	$ -	$ -	$ -
128	October	-	$ -	$ -	$ -	$ -
129	November	-	$ -	$ -	$ -	$ -
130	December	-	$ -	$ -	$ -	$ -

g) Whirlwind 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
131	December	-	$ -	$ -	$ -	$ -
132	January	-	$ -	$ -	$ -	$ -
133	February	-	$ -	$ -	$ -	$ -
134	March	-	$ -	$ -	$ -	$ -
135	April	-	$ -	$ -	$ -	$ -
136	May	-	$ -	$ -	$ -	$ -
137	June	-	$ -	$ -	$ -	$ -
138	July	-	$ -	$ -	$ -	$ -
139	August	-	$ -	$ -	$ -	$ -
140	September	-	$ -	$ -	$ -	$ -
141	October	-	$ -	$ -	$ -	$ -
142	November	-	$ -	$ -	$ -	$ -
143	December	-	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
145	January	-	$ -	$ -	$ -	$ -
146	February	-	$ -	$ -	$ -	$ -
147	March	-	$ -	$ -	$ -	$ -
148	April	-	$ -	$ -	$ -	$ -
149	May	-	$ -	$ -	$ -	$ -
150	June	-	$ -	$ -	$ -	$ -
151	July	-	$ -	$ -	$ -	$ -
152	August	-	$ -	$ -	$ -	$ -
153	September	-	$ -	$ -	$ -	$ -
154	October	-	$ -	$ -	$ -	$ -
155	November	-	$ -	$ -	$ -	$ -
156	December	-	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
158	January	-	$ -	$ -	$ -	$ -
159	February	-	$ -	$ -	$ -	$ -
160	March	-	$ -	$ -	$ -	$ -
161	April	-	$ -	$ -	$ -	$ -
162	May	-	$ -	$ -	$ -	$ -
163	June	-	$ -	$ -	$ -	$ -
164	July	-	$ -	$ -	$ -	$ -
165	August	-	$ -	$ -	$ -	$ -
166	September	-	$ -	$ -	$ -	$ -
167	October	-	$ -	$ -	$ -	$ -
168	November	-	$ -	$ -	$ -	$ -
169	December	-	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
171	January	-	$ -	$ -	$ -	$ -
172	February	-	$ -	$ -	$ -	$ -
173	March	-	$ -	$ -	$ -	$ -
174	April	-	$ -	$ -	$ -	$ -
175	May	-	$ -	$ -	$ -	$ -
176	June	-	$ -	$ -	$ -	$ -
177	July	-	$ -	$ -	$ -	$ -
178	August	-	$ -	$ -	$ -	$ -
179	September	-	$ -	$ -	$ -	$ -
180	October	-	$ -	$ -	$ -	$ -
181	November	-	$ -	$ -	$ -	$ -
182	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:		**Cite:**
183	CWIP:	-	-
184	ROE adder:	- %	-
185	100% Abandoned Plant:	-	-
	B) Tehachapi Incentives Received:		**Cite:**
186	CWIP:	-	-
187	ROE adder:	- %	-
188	100% Abandoned Plant:	-	-
	C) Devers to Colorado River Incentives Received:		**Cite:**
189	CWIP:	-	-
190	ROE adder:	- %	-
191			
192	100% Abandoned Plant:	-	-
	D) Devers to Palo Verde 2 Incentives Received:		**Cite:**
193	CWIP:	-	-
194			
195	ROE adder:	- %	-
196			
197	100% Abandoned Plant:	-	-
	E) South of Kramer Incentives Received:		**Cite:**
198	CWIP:	-	-
199	ROE adder:	- %	-
200	100% Abandoned Plant:	-	-
	F) West of Devers Incentives Received:		**Cite:**
201	CWIP:	-	-
202	ROE adder:	- %	-
203	100% Abandoned Plant:	-	-
	G) Red Bluff Incentives Received:		**Cite:**
204	CWIP:	-	-
205	ROE adder:	- %	-
206	100% Abandoned Plant:	-	-
	H) Whirlwind Substation Expansion Incentives Received:		**Cite:**
207	CWIP:	-	-
208	ROE adder:	- %	-
209	100% Abandoned Plant:	-	-
	I) Colorado River Substation Expansion Incentives Received:		**Cite:**
210	CWIP:	-	-
211	ROE adder:	- %	-
212	100% Abandoned Plant:	-	-
	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.

Schedule 15
Incentive Adders

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		- %	1-BaseTRR, L 47
2	CTR = Composite Tax Rate		- %	1-BaseTRR, L 59
3		IREF =	$ -	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	- %	--	14-IncentivePlant, L 184
5	2) Tehachapi	- %	--	14-IncentivePlant, L 187
6	3) Devers to Col. River	- %	--	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	$ -	--	$ -	14-IncentivePlant, L 13, Col. 1
10	2) Tehachapi	$ -	--	$ -	14-IncentivePlant, L 14, Col. 1
11	3) Devers to Col. River	$ -	--	$ -	14-IncentivePlant, L 15, Col. 1
12					
13	…				
14			Prior Year Incentive Adder =	$ -	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	$ -	--	$ -	14-IncentivePlant, L 19, Col. 1
16	2) Tehachapi	$ -	--	$ -	14-IncentivePlant, L 20, Col. 1
17	3) Devers to Col. River	$ -	--	$ -	14-IncentivePlant, L 21, Col. 1
18					
19	…				
20			True-Up Incentive Adder =	$ -	Sum of above PY Incentive Adders for each individual project

Schedule 15
Incentive Adders

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	$ -	14-IncentivePlant, L 19, Col. 3
22	2) Tehachapi	$ -	14-IncentivePlant, L 20, Col. 3
23	3) Devers to Col. River	$ -	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	$ -	$ -	See Note 1
26	2) Tehachapi	$ -	$ -	See Note 1
27	3) Devers to Col. River	$ -	$ -	See Note 1
28				See Note 1
29	…			
30		Total:	$ -	

c) Equity Portion of Plant In Service Rate Base

Line		Amount	Source
31	Total Rate Base:	$ -	4-TUTRR, Line 18
32	CWIP Portion of Rate Base:	$ -	4-TUTRR, Line 14
33	Plant In Service Rate Base:	$ -	Line 31 - Line 32
34	Equity percentage:	- %	1-BaseTRR, Line 47
35	Equity Portion of Plant In Service Rate Base:	$ -	Line 33 * Line 34

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

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

Schedule 16
Plant Additions

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	13-Month Averages:								$ -			$ -		$ -

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	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
27	February	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
28	March	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
29	April	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
30	May	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
31	June	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
32	July	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
33	August	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
34	September	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
35	October	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
36	November	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
37	December	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
38	January	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
39	February	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
40	March	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
41	April	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
42	May	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
43	June	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
44	July	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
45	August	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
46	September	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
47	October	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
48	November	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
49	December	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 16
Plant Additions

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	$ -	- %	$ -	18 Dep Rates L1
78	350.2	$ -	- %	$ -	18 Dep Rates L2
79	352	$ -	- %	$ -	18 Dep Rates L3
80	353	$ -	- %	$ -	18 Dep Rates L4
81	354	$ -	- %	$ -	18 Dep Rates L5
82	355	$ -	- %	$ -	18 Dep Rates L6
83	356	$ -	- %	$ -	18 Dep Rates L7
84	357	$ -	- %	$ -	18 Dep Rates L8
85	358	$ -	- %	$ -	18 Dep Rates L9
86	359	$ -	- %	$ -	18 Dep Rates L10
87					
88	Sum of Depreciation Expense			$ -	Sum of C4 Lines 77 to 86
89	Sum of Dec Prior Year Plant			$ -	Sum of C2 Lines 77 to 86
90					
91	Composite Depreciation Rate			- %	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

Schedule 17
Depreciation Expense

Depreciation Expense Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO Prior Year: -

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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15 Depreciation Rates (Percent per year) See Instruction 1.

16	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359
17a	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17b	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17c	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17d	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17e	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17f	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17g	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17h	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17i	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17j	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17k	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17l	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17m	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %

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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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Totals:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

37 Total Annual Depreciation Expense for Transmission Plant - ISO: $ -
38 (equals sum of monthly amounts)

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

Line		Amount	Source
56	**3) Calculation of Depreciation Expense for General Plant and Intangible Plant**		
57			
58	Total General Plant Depreciation Expense	$ -	FF1 336.10f
59	Total Intangible Plant Depreciation Expense	$ -	FF1 336.1f
60	Sum of Total General and Total Intangible Depreciation Expense	$ -	Line 58 + Line 59
61	Transmission Wages and Salaries Allocation Factor	- %	27-Allocators, Line 9
62	General and Intangible Depreciation Expense	$ -	Line 60 * Line 61
63			
64	**4) Depreciation Expense**		
65			
66	Depreciation Expense is the sum of:	**Amount**	**Source**
67	1) Depreciation Expense for Transmission Plant - ISO	$ -	Line 37, Col 12
68	2) Depreciation Expense for Distribution Plant - ISO	$ -	Line 53
69	3) General and Intangible Depreciation Expense	$ -	Line 62
70	Depreciation Expense:	$ -	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 are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet 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.

Schedule 18
Depreciation Rates

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%

Notes: 1) Depreciation rates may only be revised as approved by the Commission pursuant to a Section 205 or 206 filing.

Schedule 19
Operations and Maintenance

Operations and Maintenance Expenses

Cells shaded yellow are input cells

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

Line	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
	Transmission Accounts										
1	560 - Operations Supervision and Engineering - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
2	560 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
3	561 Load Dispatch - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
4	561.400 Scheduling, System Control and Dispatch Services	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
5	561.500 Reliability Planning and Standards Development	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
6	562 - Station Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
7	562 - MOGS Station Expense	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
8	562 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
9	563 - Overhead Line Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
10	564 - Underground Line Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
11	565 - Transmission of Electricity by Others	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
12	565 - Wheeling Costs	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
13	565 - WAPA Transmission for Remote Service	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
14	566 - Miscellaneous Transmission Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
15	566 - ISO/RSBA/TSP Balancing Accounts	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
16	566 - Sylmar/Palo Verde/Other General Functions	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
17	567 - Line Rents - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
18	567 - Eldorado	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
19	567 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
20	568 - Maintenance Supervision and Engineering - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
21	568 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
22	569 - Maintenance of Structures - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
23	569 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
24	570 - Maintenance of Station Equipment - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
25	570 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
26	571 - Maintenance of Overhead Lines - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
27	571 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
28	572 - Maintenance of Underground Lines - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
29	572 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
30	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
31	…	---	---	---	---	---	---	---			
32	Transmission NOIC (Note 3)	-	-	-		$ -	$ -	$ -	$ -	$ -	$ -
33	**Total Transmission O&M**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											

Schedule 19
Operations and Maintenance

	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	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
36	590 - Maintenance Supervision and Engineering	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
37	591 - Maintenance of Structures	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
38	592 - Maintenance of Station Equipment	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
39	Accounts with no ISO Distribution Costs	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
40	Distribution NOIC (Note 3)	-	-	-		$ -	$ -	$ -	$ -	$ -	$ -
41	**Total Distribution O&M**	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
42											
43	**Total Transmission and Distribution O&M**	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
44											
45	Total Transmission O&M Expenses in FERC Form 1:	$ -	FF1 321.112b	Must equal Line 33, Column 2.							
46	Total Distribution O&M Expenses in FERC Form 1:	$ -	FF1 322.156b	Must equal Line 41, Column 2.							
47	Total TDBU NOIC	$ -	20-AandG, Note 2, f								

Schedule 19
Operations and Maintenance

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

Line	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
	Transmission Accounts								
48	560 - Operations Supervision and Engineering - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
49	560 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
50	561 Load Dispatch - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
51	561.400 Scheduling, System Control and Dispatch Services	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
52	561.500 Reliability Planning and Standards Development	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
53	562 - Station Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
54	562 - MOGS Station Expense	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
55	562 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
56	563 - Overhead Line Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
57	564 - Underground Line Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 36
58	565 - Transmission of Electricity by Others	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
59	565 - Wheeling Costs	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
60	565 - WAPA Transmission for Remote Service	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
61	566 - Miscellaneous Transmission Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
62	566 - ISO/RSBA/TSP Balancing Accounts	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
63	566 - Sylmar/Palo Verde/Other General Functions	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
64	567 - Line Rents - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
65	567 - Eldorado	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
66	567 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
67	568 - Maintenance Supervision and Engineering - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
68	568 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
69	569 - Maintenance of Structures - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
70	569 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
71	570 - Maintenance of Station Equipment - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
72	570 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
73	571 - Maintenance of Overhead Lines - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
74	571 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
75	572 - Maintenance of Underground Lines - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 36
76	572 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
77	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
78	…	---	---	---	---	---	---	---	
79	Transmission NOIC (Note 4)	-	-	-		$ -	$ -	-	
80	**Total Transmission - ISO O&M**	$ -	$ -	$ -		$ -	$ -	$ -	
81									

Schedule 19
Operations and Maintenance

	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	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
83	590 - Maintenance Supervision and Engineering	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
84	591 - Maintenance of Structures	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
85	592 - Maintenance of Station Equipment	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
86	Accounts with no ISO Distribution Costs	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
87	Distribution NOIC (Note 4)	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
88	**Total Distribution - ISO O&M**	$ -	$ -	$ -		$ -	$ -	$ -	
89									
90									
91	**Total ISO O&M Expenses (in Column 6)**	$ -	$ -	$ -		$ -	$ -	$ -	
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: ---

	Percentage	Calculation
Transmission NOIC Percentage:	- %	Line 33, Col 3 / Line 43, Col 3
Distribution NOIC Percentage:	- %	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: - %

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.

Schedule 20
Administrative and General Expenses

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	$ -	FF1 323.181b	$ -	$ -	
2	921	Office Supplies and Expenses	$ -	FF1 323.182b	$ -	$ -	
3	922	A&G Expenses Transferred	$ -	FF1 323.183b	$ -	$ -	Credit
4	923	Outside Services Employed	$ -	FF1 323.184b	$ -	$ -	
5	924	Property Insurance	$ -	FF1 323.185b	$ -	$ -	
6	925	Injuries and Damages	$ -	FF1 323.186b	$ -	$ -	
7	926	Employee Pensions and Benefits	$ -	FF1 323.187b	$ -	$ -	
8	927	Franchise Requirements	$ -	FF1 323.188b	$ -	$ -	
9	928	Regulatory Commission Expenses	$ -	FF1 323.189b	$ -	$ -	
10	929	Duplicate Charges	$ -	FF1 323.190b	$ -	$ -	
11	930.1	General Advertising Expense	$ -	FF1 323.191b	$ -	$ -	
12	930.2	Miscellaneous General Expense	$ -	FF1 323.192b	$ -	$ -	
13	931	Rents	$ -	FF1 323.193b	$ -	$ -	
14	935	Maintenance of General Plant	$ -	FF1 323.196b	$ -	$ -	
15			$ -		Total A&G Expenses:	$ -	

Line	Description	Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	$ -	Line 15
17	Less Account 924:	$ -	Line 5
18	Amount to apply the Transmission W&S AF:	$ -	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	- %	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	$ -	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	- %	27-Allocators, Line 22
22	Property Insurance portion of A&G:	$ -	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$ -	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	$ -	$ -	$ -	$ -	$ -	See Instructions 2b, 3, and Note 2
25	921	$ -	$ -	$ -	$ -	$ -	
26	922	$ -	$ -	$ -	$ -	$ -	
27	923	$ -	$ -	$ -	$ -	$ -	
28	924	$ -	$ -	$ -	$ -	$ -	
29	925	$ -	$ -	$ -	$ -	$ -	
30	926	$ -	$ -	$ -	$ -	$ -	See Note 3
31	927	$ -	$ -	$ -	$ -	$ -	See Note 4
32	928	$ -	$ -	$ -	$ -	$ -	
33	929	$ -	$ -	$ -	$ -	$ -	
34	930.1	$ -	$ -	$ -	$ -	$ -	
35	930.2	$ -	$ -	$ -	$ -	$ -	
36	931	$ -	$ -	$ -	$ -	$ -	
37	935	$ -	$ -	$ -	$ -	$ -	

Schedule 20
Administrative and General Expenses

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:	$ -	SCE Records
b	Actual A&G NOIC payout:	$ -	Note 2, d
c	Adjustment:	$ -	

Actual non-capitalized NOIC Payouts:

	Department	Amount	Source
d	A&G	$ -	SCE Records and Workpapers
e	Other	$ -	SCE Records and Workpapers
f	Trans. And Dist. Business Unit	$ -	SCE Records and Workpapers
g	Total:	$ -	Sum of d to f

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
a	Current Authorized PBOPs Expense Amount:	$18,219,000	See instruction #4
b	Prior Year Authorized PBOPs Expense Amount	$ -	Authorized PBOPs Expense Amount during Prior Year
c	Prior Year FF1 PBOPs expense:	$ -	SCE Records
d	PBOPs Expense Exclusion:	$ -	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: ----
5) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 20.

Schedule 21
Revenue Credits

	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.	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
1b	450	4191115	Residential Late Payment	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
2	**450 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
3	**FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)**			$ -										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4c	451	4192110	Miscellaneous Service Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4d	451	4192115	Returned Check Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4e	451	4192125	Service Reconnection Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4f	451	4192130	Service Establishment Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4g	451	4192140	Field Collection Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4h	451	4192510	Quickcheck Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
4i	451	4192910	PUC Reimbursement Fee-Elect	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
4j	451	4182120	Uneconomic Line Extension	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4k	451	4192152	Opt Out CARE-Res-Ini	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4l	451	4192155	Opt Out CARE-Res-Mo	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4m	451	4192158	Opt Out NonCARE-Res-Ini	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4n	451	4192160	Opt Out NonCARE-Res-Mo	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4o	451	4192135	Conn-Charge - Residential	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4p	451	4192145	Conn-Charge - Non-Residential	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4q	451	4192150	Conn-Charge - At Pole	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
5	**451 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
6	**FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)**			$ -										
8	**453 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
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	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10d	454	4184120	Joint Pole - Aud - Unauth Penalty	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10e	454	4184510	Joint Pole - Non-Tariffed Pole Rental	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10f	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10g	454	4184514	Joint Pole - Non-Tariff Requests for Information	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10h	454	4184516	Oil And Gas Royalties	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10i	454	4184518	Def Operating Land & Facilities Rent Rev	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10j	454	4184810	Facility Cost -EIX/Nonutility	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
10k	454	4184815	Facility Cost- Utility	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
10l	454	4184820	Rent Billed to Non-Utility Affiliates	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
10m	454	4184825	Rent Billed to Utility Affiliates	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
10n	454	4194110	Meter Leasing Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
10o	454	4194115	Company Financed Added Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10p	454	4194120	Company Financed Interconnect Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10q	454	4194130	SCE Financed Added Faclty	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10r	454	4194135	Interconnect Facility Finance Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	8
10s	454	4204515	Operating Land & Facilities Rent Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10t	454	4867020	Nonoperating Misc Land & Facilities Rent	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10u	454	-	Miscellaneous Adjustments	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
10v	454	4206515	Op Misc Land/Fac Rev	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10w	454	4184122	T-Unauth Pole Rent	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10x	454	4184124	T-P&E Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
11	**454 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
12	**FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)**			$ -										

Schedule 21
Revenue Credits

	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	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12c	456	4186120	Added Facilities - One Time Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	3
12e	456	4186126	Service Fee - Optimal Bill Prd	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12f	456	4186128	Miscellaneous Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12g	456	4186130	Tule Power Plant - Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	3
12h	456	4186142	Microwave Agreement	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12i	456	4186150	Utility Subs Labor Markup	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
12j	456	4186155	Non Utility Subs Labor Markup	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12l	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12p	456	4186194	Property License Fee revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12q	456	4186512	Revenue From Recreation, Fish & Wildlife	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12r	456	4186514	Mapping Services	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12s	456	4186518	Enhanced Pump Test Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12t	456	4186524	Revenue From Scrap Paper - General Office	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12u	456	4186528	CTAC Revenues	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12v	456	4186530	AGTAC Revenues	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12w	456	4186716	ADT Vendor Service Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12x	456	4186718	Read Water Meters - Irvine Ranch	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12y	456	4186720	Read Water Meters - Rancho California	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12z	456	4186722	Read Water Meters - Long Beach	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12aa	456	4186730	SSID Transformer Repair Services Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12bb	456	4186815	Employee Transfer/Affiliate Fee	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12cc	456	4186910	ITCC/CIAC Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12dd	456	4186912	Revenue From Decommission Trust Fund	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ee	456	4186914	Revenue From Decommissioning Trust FAS115	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ff	456	4186916	Offset to Revenue from NDT Earnings/Realized	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12gg	456	4186918	Offset to Revenue from FAS 115 FMV	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12hh	456	4186920	Revenue From Decommissioning Trust FAS115-1	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ii	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12jj	456	4188712	Power Supply Installations - IMS	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12kk	456	4188714	Consulting Fees - IMS	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12ll	456	4196105	DA Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12mm	456	4196158	EDBL Customer Finance Added Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12nn	456	4196162	SCE Energy Manager Fee Based Services	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12oo	456	4196166	SCE Energy Manager Fee Based Services Adj	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12pp	456	4196172	Off Grid Photo Voltaic Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12qq	456	4196174	Scheduling/Dispatch Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12rr	456	4196176	Interconnect Facilities Charges-Customer Financed	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	8
12ss	456	4196178	Interconnect Facilities Charges - SCE Financed	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12tt	456	4196184	DMS Service Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12uu	456	4196188	CCA - Information Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12vv	456	-	Miscellaneous Adjustments	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12ww	456	4186911	Grant Amortization	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12xx	456	4186925	GHG Allowance Revenue	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
13	**456 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
14	**FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)**			$ -										

Schedule 21
Revenue Credits

	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	$ -	$ -	$ -	$ -		$ -	$ -	$ -	5
15b	456.1	4188114	FTS PPU/Non-ISO	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15f	456.1	4188816	ISO-Congestion Revenue	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15g	456.1	4198110	Transmission of Elec of Others	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	5
15h	456.1	4198112	WDAT	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15j	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15k	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15l	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15m	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15n	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15o	456.1	4198126	High Desert Tie-Line Rental Rev	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15p	456.1	4198130	Inland Empire CRT Tie-Line EX	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15q	456.1	4198910	Reliability Service Revenue - Non-PTO's	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
16	**456.1 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
17	**FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)**			$ -										
18a														
19	**457.1 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
20	**FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)**			$ -										
21a														
22	**457.2 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
23	**FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)**			$ -										
	Edison Carrier Solutions (ECS)													
24a	417	4863130	ECS - Distribution Facilities	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24b	417	4862110	ECS - Dark Fiber	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24c	417	4862115	ECS - SCE Net Fiber	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24d	417	4862120	ECS - Transmission Right of Way	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24e	417	4862135	ECS - Wholesale FCC	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24f	417	4864115	ECS - EU FCC Rev	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24g	417	4862125	ECS - Cell Site Rent and Use (Active)	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24h	417	4862130	ECS - Cell Site Reimbursable (Active)	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24i	417	4863120	ECS - Communication Sites	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24j	417	4863110	ECS - Cell Site Rent and Use (Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24k	417	4863115	ECS - Cell Site Reimbursable (Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24l	417	4863125	ECS - Micro Cell	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24m	417	4864120	ECS - End User Universal Service Fund Fee	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
25	**417 ECS Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
26	**417 Other**			$ -										
27	**FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)**			$ -										

Schedule 21
Revenue Credits

	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	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2,9
28b	418.1		ESI (Gross Revenues - Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2,9
28c	418.1		Southern States Realty	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2, 15
28d	418.1		Mono Power Company	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	13
28e	418.1		Edison Material Supply (EMS)	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7, 17
29	**418.1 Subsidiaries Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
30	**418.1 Other (See Note 16)**			$ -										
31	**FF-1 Total for Account 418.1 -Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)**			$ -										
32			**Totals**	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	

Line		Description	Amount	Calculation
33		Ratepayers' Share of Threshold Revenue	$ -	= Line 32K
34		ISO Ratepayers' Share of Threshold Revenue	$ -	Note 11
35				
36		Total Active Incremental Revenue	$ -	= Sum Active categories in column L
37		Ratepayers' Share of Active Incremental Revenue	$ -	= Line 36D * 10%
38		Total Passive Incremental Revenue	$ -	= Sum Passive categories in column L
39		Ratepayers' Share of Passive Incremental Revenue	$ -	= Line 38D * 30%
40		Total Ratepayers' Share of Incremental Revenue	$ -	= Line 37D + Line 39D
41		ISO Ratepayers' Share of Incremental Revenue (%)	- %	see Note 11
42		ISO Ratepayers' Share of Incremental Revenue	$ -	= Line 40D * Line 41D
43		**Tot. ISO Ratepayers' Share NTP&S Gross Rev.**	$ -	= Line 34D + Line 42D

Line		Amount	Calculation
44	**Total Revenue Credits:**	$ -	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 = - % Source: ---

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 = - % Source: ---

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.

Schedule 22
Network Upgrade Credits and Interest Expense

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	$ -	See Note 1
2	Acct 252 Other	$ -	Line 3 - Line 1
3	Total Acct 252 - Customer Advances for Construction	$ -	FF1 113.56d
	2) End of Year Balances: (Note 2)		
4	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$ -	See Note 3
5	Acct 252 Other	$ -	Line 6 - Line 4
6	Total Acct 252 - Customer Advances for Construction	$ -	FF1 113.56c
7	Average Outstanding Network Upgrade Credits Beginning and End of Year	$ -	(Line 1 + Line 4) / 2
8	Interest On Network Upgrade Credits Recorded in FERC Acct 242	$ -	See Note 4
9	Acct 242 Other	$ -	Line 10 - Line 8
10	Total Acct 242 - Miscellaneous Current and Accrued Liabilities	$ -	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.

Schedule 23
Regulatory Assets and Liabilities

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

Line

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

Line		Prior Year Amount	Calculation or Source
12			
13			
14	Other Regulatory Assets/Liabilities (EOY):	$ -	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	$ -	Avg. of Sum of Cols. 1 and 2 below
16	Amortization and Regulatory Debits/Credits:	$ -	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:	$ -	$ -	$ -	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.

Schedule 24
CWIP TRR

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:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 80
2	Devers to Colorado River:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 106
3	South of Kramer:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 132
4	West of Devers:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 158
5	Red Bluff:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 184
6	Whirlwind Sub Expansion:	$ -	$ -	$ -	10-CWIP, Lines 27, 28, 210
7	Colorado River Sub Expansion:	$ -	$ -	$ -	10-CWIP, Lines 27, 28, 236
8		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 262
9		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 288
10		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 314
11		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 340
12	Totals:	$ -	$ -	$ -	Sum of Lines 1 to 11

b) Return:

Line		EOY Amount	Average Amount	Source
13	CWIP Amount:	$ -	$ -	Line 12
14	Cost of Capital Rate:	- %	- %	1-BaseTRR, Line 54
15	Cost of Capital:	$ -	$ -	Line 13 * Line 14

c) Income Taxes

Line		EOY Amount	Average Amount	Source
16	CWIP Amount:	$ -	$ -	Line 12
17	Equity ROR w Preferred Stock ("ER"):	- %	- %	1-BaseTRR, Line 55
18	Composite Tax Rate:	- %	- %	1-BaseTRR, Line 59
19	Income Taxes:	$ -	$ -	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 =	$ -	15-IncentiveAdder, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	Source
25	Tehachapi CWIP Amount:	$ -	$ -	Line 1
26	ROE Adder %:	- %	- %	15-IncentiveAdder, Line 5
27	ROE Adder $:	$ -	$ -	Formula on Line 32

2) Devers to Colorado River

Line		EOY Amount	Average Amount	Source
28	DCR CWIP Amount:	$ -	$ -	Line 2
29	ROE Adder %:	- %	- %	15-IncentiveAdder, Line 6
30	ROE Adder $:	$ -	$ -	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:	$ -	$ -	Line 15
34	Income Taxes:	$ -	$ -	Line 19
35	ROE Adder Tehachapi:	$ -	$ -	Line 27
36	ROE Adder DCR:	$ -	$ -	Line 30
37	FF&U:	$ -	$ -	Note 1
38	Total:	$ -	$ -	Sum Lines 33 to 37

Schedule 24
CWIP TRR

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:	$ -	$ -	$ -	$ -	$ -	Note 2
40	Devers to Colorado River:	$ -	$ -	$ -	$ -	$ -	Note 2
41	South of Kramer:	$ -	$ -	$ -	$ -	$ -	Note 2
42	West of Devers:	$ -	$ -	$ -	$ -	$ -	Note 2
43	Red Bluff:	$ -	$ -	$ -	$ -	$ -	Note 2
44	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 2
45	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 2
46		$ -	$ -	$ -	$ -	$ -	Note 2
47		$ -	$ -	$ -	$ -	$ -	Note 2
48		$ -	$ -	$ -	$ -	$ -	Note 2
49		$ -	$ -	$ -	$ -	$ -	Note 2
50	Totals:	$ -	$ -	$ -	$ -	$ -	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:	$ -	$ -	$ -	$ -	$ -	Note 3
52	Devers to Colorado River:	$ -	$ -	$ -	$ -	$ -	Note 3
53	South of Kramer:	$ -	$ -	$ -	$ -	$ -	Note 3
54	West of Devers:	$ -	$ -	$ -	$ -	$ -	Note 3
55	Red Bluff:	$ -	$ -	$ -	$ -	$ -	Note 3
56	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 3
57	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 3
58		$ -	$ -	$ -	$ -	$ -	Note 3
59		$ -	$ -	$ -	$ -	$ -	Note 3
60		$ -	$ -	$ -	$ -	$ -	Note 3
61		$ -	$ -	$ -	$ -	$ -	Note 3
62	Totals:	$ -	$ -	$ -	$ -	$ -	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:	$ -	Line 12, Col 3
64	AFCRCWIP:	- %	2-IFPTRR, Line 16
65	CWIP component of IFPTRR without FF&U:	$ -	Line 63 * Line 64
66	FF&U:	$ -	Line 65 * (28-FFU, L5 FF Factor + U Factor)
67	CWIP component of IFPTRR including FF&U:	$ -	Line 65 + Line 66

b) Individual Project Contribution

	Project	Amount wo FF&U	Amount with FF&U	Source
68	Tehachapi:	$ -	$ -	Note 4
69	Devers to Colorado River:	$ -	$ -	Note 4
70	South of Kramer:	$ -	$ -	Note 4
71	West of Devers:	$ -	$ -	Note 4
72	Red Bluff:	$ -	$ -	Note 4
73	Whirlwind Sub Expansion:	$ -	$ -	Note 4
74	Colorado River Sub Expansion:	$ -	$ -	Note 4
75		$ -	$ -	Note 4
76		$ -	$ -	Note 4
77		$ -	$ -	Note 4
78		$ -	$ -	Note 4
79	Totals:	$ -	$ -	Sum of Lines 68 to 78

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

a) Total of all CWIP projects

Line		Value	Source
80	PY Total Return, Taxes, Incentive:	$ -	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	$ -	Line 65
82	Total without FF&U:	$ -	Line 80 + Line 81
83	FF Factor:	- %	28-FFU, Line 5
84	U Factor:	- %	28-FFU, Line 5
85	Franchise Fees Amount:	$ -	Line 82 * Line 83
86	Uncollectibles Amount:	$ -	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	$ -	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	$ -	Line 82 + Line 85

b) Individual CWIP Project Contribution to the Retail Base TRR

Line		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF&U	Col 4 Total	Source
89	Tehachapi:	$ -	$ -	$ -	$ -	Note 5
90	Devers to Colorado River:	$ -	$ -	$ -	$ -	Note 5
91	South of Kramer:	$ -	$ -	$ -	$ -	Note 5
92	West of Devers:	$ -	$ -	$ -	$ -	Note 5
93	Red Bluff:	$ -	$ -	$ -	$ -	Note 5
94	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	Note 5
95	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	Note 5
96		$ -	$ -	$ -	$ -	Note 5
97		$ -	$ -	$ -	$ -	Note 5
98		$ -	$ -	$ -	$ -	Note 5
99		$ -	$ -	$ -	$ -	Note 5
100	Totals:	$ -	$ -	$ -	$ -	

c) Individual CWIP Project Contribution to the Wholesale Base TRR

Line		Col 1 PYTRR wo FF&U	Col 2 IFPTRR wo FF&U	Col 3 FF	Col 4 Total	Source
101	Tehachapi:	$ -	$ -	$ -	$ -	Note 6
102	Devers to Colorado River:	$ -	$ -	$ -	$ -	Note 6
103	South of Kramer:	$ -	$ -	$ -	$ -	Note 6
104	West of Devers:	$ -	$ -	$ -	$ -	Note 6
105	Red Bluff:	$ -	$ -	$ -	$ -	Note 6
106	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	Note 6
107	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	Note 6
108		$ -	$ -	$ -	$ -	Note 6
109		$ -	$ -	$ -	$ -	Note 6
110		$ -	$ -	$ -	$ -	Note 6
111		$ -	$ -	$ -	$ -	Note 6
112	Totals:	$ -	$ -	$ -	$ -	

Notes:

1) (Sum Lines 33 to 36) * (FF + U Factors from 28-FFU) for Prior Year TRR
   (Sum Lines 33 to 36) * (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.

Schedule 25
Wholesale Differences to Base TRR

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:

Line		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.

Line		Data Source	Value	Notes/Instructions
12	Fixed Charge Rate	2-IFPTRR Line 16	- %	1
13	Prior Year		-	2
14	Wholesale Rate Base Difference for Prior Year		$ -	3
15	Wholesale Rate Base Adjustment	Line 14 * Line 12	$ -	

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

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

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

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

Schedule 25
Wholesale Differences to Base TRR

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

3) Calculation of the Wholesale Difference to the Base TRR

		Source	**Value**	
39	Wholesale Rate Base Adjustment	Line 15	$ -	
40	Expense Difference	Line 38	$ -	
41	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 80	$ -	
42	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	$ -	
43	Subtotal:	Sum Line 39 to Line 42	$ -	
44	Franchise Fee Exclusion		$ -	Note 4
45	Wholesale Difference to the Base TRR:	Line 43 + Line 44	$ -	

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.
6) If appropriate, additional expenses may be excluded from the Wholesale Base TRR

Schedule 26
Tax Rates

Income Tax Rates

1) Federal Income Tax rate Inputs are shaded yellow

Line	Rate Year	Federal Income Tax Rate ("FITR")	Source
1	-	- %	Note 1, Note 4
2			
3	**2) Composite State Income Tax Rate**		
4			
5		**State**	
6	**Rate**	**Income Tax**	
7	**Year**	**Rate ("SITR")**	**Source**
8	-	- %	Note 2
9			
10			
11			

Line	3) Capitalized Overhead portion of Electric Payroll Tax Expense	Amount
12		
13		
14	Total Electric Payroll Tax Expense (From 1-BaseTRR, Line 31)	$ -
15	Capitalization Rate (Note 3)	- %
16	Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 * Line 15)	$ -
17	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 - Line 16)	$ -

Notes:

1) Federal Source Statute: ---

2) California State Source Statue: ---

3) Capitalization Rate approved in: ---

For the following Prior Years: ---

4) In the event that either the Federal or State Income Tax Rate applicable to the Rate Year differs from that in effect during the Prior Year, the True Up TRR for the Prior Year will be calculated utilizing the same Formula Rate Spreadsheet except for the Income Tax rate(s). The difference between the True Up TRR calculated in such workpaper using the Income Tax Rates that were in effect during the Prior Year and the True Up TRR otherwise calculated by this formula shall be entered as a One Time Adjustment on Schedule 3, ensuring that the Formula Spreadsheet correctly calculates the True Up TRR for the Prior Year to be based on the Income Tax Rate(s) that were in effect during that year. For the Prior Years of 2016 and 2017, both of which will have Income Tax Rates that differ between the Prior Year and the Rate Year due to the passage of the 2017 Tax Cuts and Jobs Act, this provision will be implemented as part of the Section 6 of the Formula Rate Protocols, which will calculate the True Up TRR for those years based on a Federal Income Tax Rate of 35%.

Schedule 27
Allocation Factors

Calculation of Allocation Factors

Inputs are shaded yellow

Line	1) Calculation of Transmission Wages and Salaries Allocation Factor	Notes	FERC Form 1 Reference or Instruction	Prior Year Value
1	ISO Transmission Wages and Salaries		19-OandM Line 91, Col. 7	$ -
2	Total Wages and Salaries		FF1 354.28b	$ -
3	Less Total A&G Wages and Salaries		FF1 354.27b	$ -
4	Total Wages and Salaries wo A&G		Line 2 - Line 3	$ -
5	Total NOIC (Non-Officer Incentive Compensation)		20-AandG, Note 2	$ -
6	Less A&G NOIC		20-AandG, Note 2	$ -
7	NOIC wo A&G NOIC		Line 5 - Line 6	$ -
8	Total non-A&G W&S with NOIC		Line 4 + Line 7	$ -
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	- %
10				

Line	2) Calculation of Transmission Plant Allocation Factor	Notes	FERC Form 1 Reference or Instruction	Prior Year Value
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	$ -
15	Distribution Plant - ISO		7-PlantStudy, Line 30	$ -
16	Total Electric Miscellaneous Intangible Plant		6-PlantInService, Line 21, C2	$ -
17	Electric Miscellaneous Intangible Plant - ISO		Line 16 * Line 9	$ -
18	Total General Plant		6-PlantInService, Line 21, C1	$ -
19	General Plant - ISO		Line 18 * Line 9	$ -
20	Total Plant In Service		FF1 207.104g	$ -
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	- %
23				

Line	Description	Values	Notes	Applied to Accounts
24	**3) Schedule 19 "Percent ISO" Allocation Factors (Input values are from SCE Records)**			
25				
26	a) Line Miles	**Values**	**Notes**	**Applied to Accounts**
27	ISO Line Miles	---		563 --Overhead Line Expenses - Allocated
28	Non-ISO Line Miles	---		567 - Line Rents - Allocated
29	Total Line Miles	---	= L27 + L28	571 - Maintenance of Overhead Lines - Allocated
30	Line MIles Percent ISO	- %	= L27 / L29	
31				
32	b) Underground Line Miles	**Values**	**Notes**	**Applied to Accounts**
33	ISO Underground Line Miles	---		564 - Underground Line Expense
34	Non-ISO Underground Line Miles	---		572 - Maintenance of Underground Transmission Lines
35	Total Undergound Line Miles	---	= L33 + L34	
36	Underground Line MIles Percent ISO	- %	= L33 / L35	
37				
38	c) Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
39	ISO Circuit Breakers	---		All Other Non 0% or 100% Transmission O&M Accounts
40	Non-ISO Breakers	---		
41	Total Circuit Breakers	---	= L39 + L40	
42	Circuit Breakers Percent ISO	- %	= L39 / L41	
43				
44	d) Distribution Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
45	ISO Distribution Circuit Breakers	---		582 - Station Expenses
46	Non-ISO Distribution Circuit Breakers	---		590 - Maintenance Supervision and Engineering
47	Total Distribution Circuit Breakers	---	= L45 + L46	591 - Maintenance of Structures
48	Distribution Circuit Breakers Percent ISO	- %	= L45 / L47	592 - Maintenance of Station Equipment

Schedule 28
FF and U

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	---	---	---	- %	---
2	---	---	---	- %	---

2) Approved Uncollectibles Expense Factor(s)

Line	From	To	Days in Prior Year	U Factor	Reference
3	---	---	---	- %	---
4	---	---	---	- %	---

3) FF and U Factors

Line	Prior Year	FF Factor	U Factor	Notes
5	---	- %	- %	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:	- %	((L1 FF Factor * L1 Days) + (L2 FF Factor * L2 Days))/(L1+L2 Days)
Prior Year U Factor:	- %	((L3 U Factor * L3 Days) + (L4 U Factor * L4 Days))/(L3+L4 Days)

Schedule 29
Wholesale TRRs

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

Inputs are shaded yellow

Line	TRR Values		Notes	Source
1	$ -	= Wholesale Base TRR		1-BaseTRR, Line 89
2	$ -	= Total Wholesale TRBAA	Note 1	---
3	$ -	= HV Wholesale TRBAA		---
4	$ -	= LV Wholesale TRBAA		---
5	$ -	= Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue
6	- %	= HV Allocation Factor		31-HVLV, Line 37
7	- %	= 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:	$ -	$ -	$ -	See Note 3
9	CWIP Component of Wholesale Base TRR:	$ -	$ -	$ -	See Note 4
10	Non-CWIP Component of Wholesale Base TRR:	$ -	$ -	$ -	See Note 5
11	Wholesale TRBAA:	$ -	$ -	$ -	Lines 2 to 4
12	Less Standby Transmission Revenues:	$ -	$ -	$ -	See Note 6
13	Components of Wholesale Transmission Revenue Requirement:	$ -	$ -	$ -	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: ---

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.

Schedule 30
Wholesale Rates

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 =	$	-		29-WholesaleTRRs, Line 13, C3
2	Gross Load =		---	MWh	32-Gross Load, Line 4
3	Low Voltage Access Charge =	$	-	per kWh	Line 1 / (Line 2 * 1000)

Calculation of High Voltage Utility Specific Rate:
(used by ISO in billing of ISO TAC)

					Source
4	SCE HV TRR =	$	-		29-WholesaleTRRs, Line 13, C2
5	Gross Load =		---	MWh	32-Gross Load, Line 4
6	High Voltage Utility-Specific Rate =	$	-	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

					Source
7	HV Wholesale TRR =	$	-		29-WholesaleTRRs, Line 13, C2
8	Sum of Monthly Peak Demands:		---	MW	32-Gross Load, Line 5
9	HV Existing Contracts Access Charge:	$	-	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.

Schedule 31
High and Low Voltage Gross Plant

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

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:

A) Total ISO Plant from Prior Year

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	LV Transmission Lines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total Transmission Lines (L 2 + L 3):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5									
6	**Substations:**								
7	HV Substations (>= 200 kV)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Straddle Subs (Cross 200 kV bound.):	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	LV Substations (Less Than 200kV)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total all Substations (L7 + L8 + L9)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11									
12	**Total Lines and Substations**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant that can directly be determined to be HV or LV:				
16					
17					
18	Land	$ -	$ -	$ -	From above Line 12
19	Structures	$ -	$ -	$ -	From above Line 12
20	Total Determined HV/LV:	$ -	$ -	$ -	Sum of lines 18 and 19
21	Gross Plant Percentages (Prior Year):	- %	- %		Percent of Total
22					
23	Straddling Transformers	$ -	$ -	$ -	Straddling Transformers split by Gross Plant Percentages on Line 21
24	Abandoned Plant (BOY)	$ -	$ -	$ -	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	$ -	$ -	$ -	Line 20 + Line 23 + Line 24
26					
27					

Line	**B) Gross Plant Percentage for the Rate Year:**	High Voltage	Low Voltage	Total	Notes:
28					
29					
30					
31					
32	Total HV and LV Gross Plant for Prior Year	$ -	$ -	$ -	Line 25
33	In Service Additions in Rate Year:	$ -	$ -	$ -	13-Month Average: 16-PlantAdditions, Line 25, Cols 7 (for Total) and 12 (for LV). HV = C7 - C12.
34	CWIP in Rate Year	$ -	$ -	$ -	13 Month Average: 10-CWIP, Line 54, Col. 8
35	Total HV and LV Gross Plant for Rate Year	$ -	$ -	$ -	Line 32 + Line 33 + Line 34
36					
37	HV and LV Gross Plant Percentages:	- %	- %		Percent of Total on Line 35
38	(HV Allocation Factor and				
39	LV Allocation Factor)				

Schedule 32
Gross Load

Calculation of Forecast Gross Load

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	---		Note 1
2	Pump Load forecast:	---		Note 2
3	Pump Load True-Up:	---		Note 4
4	Forecast Gross Load:	---	Line 1 + Line 2 + Line 3	Sum of above
5	Forecast 12-CP Retail Load:	---		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.
4) The Pump Load True-Up value is equal to actual recorded less forecast Pump Load for the Prior Year.

Calculation of SCE Retail Transmission Rates

		Source	
Retail Base TRR:	$ -	1-BaseTRR WS, Line 86	Input cells are shaded yellow

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

Line	CPUC Rate Group	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)	Recorded Billing Determinants: to be applied to the Supplemental kW demand charges, and the Contracted Standby 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	- %	$ -						---	$ -					
1b	TOU-GS-1	- %	$ -						---	$ -					
$1b_2$	TOU-GS-1 continued								---		---	---	---	---	Notes 9,10
1c	TC-1	- %	$ -						---	$ -					
1d	TOU-GS-2	- %	$ -						---		$ -				
1e	TOU-GS-3	- %	$ -						---		$ -				
1f	TOU-8-SEC	- %	$ -						---		$ -				
1g	TOU-8-PRI	- %	$ -						---		$ -				
1h	TOU-8-SUB	- %	$ -						---		$ -				
1i	TOU-8-Standby-SEC	- %	$ -						---		$ -				
1j	TOU-8-Standby-PRI	- %	$ -						---		$ -				
1k	TOU-8-Standby-SUB	- %	$ -						---		$ -				
1l	TOU-PA-2	- %	$ -						---		$ -				
1m	TOU-PA-3	- %	$ -						---		$ -				
1n	Street Lighting	- %	$ -						---	$ -					
1o	---								---						
2	Totals:	- %	$ -	---	---	---	---	---	---						
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
6									
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	$ -	---	$ -		TOU-8-SEC	$ -	---	$ -
9b	TOU-8-Standby-PRI	$ -	---	$ -		TOU-8-PRI	$ -	---	$ -
9c	TOU-8-Standby-SUB	$ -	---	$ -		TOU-8-SUB	$ -	---	$ -
9d	---					---			
10									

11 **3) End-User Transmission Rates**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
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		= Line16:Col2 / (Line1:Col8 * 10^6)
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**	Transportation Electrification (TE) Energy Charge - $/kWh
16a	Domestic	$ -	$ -			$ -						
16b	TOU-GS-1	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	Note 15	$ -
16c	TC-1	$ -	$ -			$ -						
16d	TOU-GS-2	$ -	$ -	$ -			$ -	$ -			Note 16	$ -
16e	TOU-GS-3	$ -	$ -	$ -			$ -	$ -				$ -
16f	TOU-8-SEC	$ -	$ -				$ -					$ -
16g	TOU-8-PRI	$ -	$ -				$ -					$ -
16h	TOU-8-SUB	$ -	$ -				$ -					$ -
16i	TOU-8-Standby-SEC	$ -	$ -	$ -			$ -	$ -				
16j	TOU-8-Standby-PRI	$ -	$ -	$ -			$ -	$ -				
16k	TOU-8-Standby-SUB	$ -	$ -	$ -			$ -	$ -				
16l	TOU-PA-2	$ -	$ -	$ -			$ -	$ -	$ -	$ -	Note 17	
16m	TOU-PA-3	$ -	$ -	$ -			$ -	$ -				
16n	Street Lighting	$ -	$ -			$ -						
16o	---											
17	Totals:	$ -	$ -	$ -								

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:Col10~~9~~
15) Applicable to time-of-use schedules within the GS-1 rate group
16) Rates associated with Rate Groups GS-2 and TOU-GS-3 are calculated on a combined basis, so that the rate is the sum of the combined Revenue Associated with Supplemental Demand or Energy in Column 2 (line 16d and 16e) divided by the sum of the sum of the Billing Determinants in Column 8 (Line 1d and 1e).
17) Applicable to the optional schedules that contain horse power charge such as PA-1
18) 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, TOU-D-T-CPP, TOU-D (Options 4-9 PM, 5-8 PM, PRIME, and CPP)
26b	TOU-GS-1	Includes Schedules GS-1, TOU-EV-3, TOU-EV-7 (Options D and E), and TOU-GS-1 (Options E, ES, D, LG, C, 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	TOU-GS-2	Includes Schedules GS-2, TOU-EV-4, TOU-EV-8, and TOU-GS-2 (Options D, E, A, B, R, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26e	TOU-GS-3	Includes Schedules TOU-GS-3-CPP, TOU-EV-8, and TOU-GS-3 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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 (Options D, LG, A, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26j	TOU-8-Standby-PRI	Includes Schedules TOU-8-Standby (Options D, LG, A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26k	TOU-8-Standby-SUB	Includes Schedules TOU-8-Standby (Options D, LG, 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 (Options D, E, 4-9 PM, 5-8 PM, 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 (Options D, E, 4-9 PM, 5-8 PM, A, B, RTP, SOP-1, SOP-2, Standby, and AP-I).
26n	Street Lighting	Includes Schedules AL-2, AL-2-B, AL-2-F, 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	CPUC Rate Group	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+Col 2+Col3)/3			from Line1:Col3	from Line1:Col4	= Col 7 + Col 8	= Line35:(Col4*Col5 /Col6*Col9)	= Line35:(Col10 / total of Col10)
32								Note 18				
33		12-CP MW									MW	
34	**CPUC Rate Group**				**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				---			---	---	---	---	- %
35b	TOU-GS-1				---			---	---	---	---	- %
35c	TC-1				---			---	---	---	---	- %
35d	TOU-GS-2				---			---	---	---	---	- %
35e	TOU-GS-3				---			---	---	---	---	- %
35f	TOU-8-SEC				---			---	---	---	---	- %
35g	TOU-8-PRI				---			---	---	---	---	- %
35h	TOU-8-SUB				---			---	---	---	---	- %
35i	TOU-8-Standby-SEC				---			---	---	---	---	- %
35j	TOU-8-Standby-PRI				---			---	---	---	---	- %
35k	TOU-8-Standby-SUB				---			---	---	---	---	- %
35l	TOU-PA-2				---			---	---	---	---	- %
35m	TOU-PA-3				---			---	---	---	---	- %
35n	Street Lighting				---			---	---	---	---	- %
35o	---											
36	Totals:	---	---	---	---	---	---	---	---	---	---	- %

Schedule 34
Unfunded Reserves

Determination of Unfunded Reserves

Line					
1					
2					
3					**Prior Year**
4		**Reference**			**Amount**
5					
6	**Unfunded Reserves (EOY):**	(Line 17, Col 2)			$ -
7	**Unfunded Reserves (Average BOY/EOY):**	(Line 17, Col 3)			$ -
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)	$ -	$ -	$ -
15	Provision for Vac/Sick Leave	(Line 29)	$ -	$ -	$ -
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	$ -	$ -	$ -
17	Totals:	(Line 14 + Line 15 + Line 16)	$ -	$ -	$ -
18					
19	**Calculations**				
20					Average
21	**Injuries and Damages**		BOY	EOY	BOY/EOY
22	Injuries and Damages - Note 1	Company Records - Input (Negative)	$ -	$ -	
23	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	$ -	$ -	$ -
25					
26	**Vacation Leave**				
27	Vacation and Personal Time Accruals - Acct. 2350080	Company Records - Input (Negative)	$ -	$ -	
28	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	$ -	$ -	$ -
30					
31	**Supplemental Executive Retirement Plan**				
32	Supplemental Executive Retirement Plan	Company Records - Input (Negative)	$ -	$ -	
33	Times:	Applicable Rate Base Percentage	50%	50%	
34	Sub-Total Supplemental Executive Retirement Plan	(Line 32 x Line 33)	$ -	$ -	
35	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	$ -	$ -	$ -

Notes:

1) Includes any Unfunded Reserves relating to accrued expenses included in Account 925 “Injuries and Damages”, reduced for any expected offsetting payments.

RED-LINED VERSION OF

SCE'S TO TARIFF SHEETS

REFLECTING THE PROPOSED

FORMULA RATE

APPENDIX IX

ATTACHMENT 1

FORMULA RATE PROTOCOLS

1. INTRODUCTION

SCE shall calculate its Base Transmission Revenue Requirement ("Base TRR"), as defined in Section 3.6 of the main definitions section of this TO Tariff, using the formula rate that is presented in spreadsheet format in Attachment 2 to Appendix IX ("Formula Rate Spreadsheet").[1] The Formula Rate Spreadsheet contains fixed formulae that are only subject to change pursuant to Sections 205 and 206 of the Federal Power Act, and will be populated with data from SCE's annual Federal Energy Regulatory Commission ("FERC" or the "Commission") Form 1 filing or from other SCE records. The sources of the data used in the Formula Rate will be: (a) identified in the Formula Rate Spreadsheet by fixed references to specific locations in FERC Form 1, or (b) provided by SCE in accordance with Section 3 of these Protocols.

The Base TRR shall be calculated annually in accordance with the Formula Rate and shall be equal to the sum of the Prior Year TRR, the Incremental Forecast Period TRR, and the True Up Adjustment. Additionally, SCE shall include a Cost Adjustment in the Base TRR for the upcoming Rate Year in the event that a discrete cost of service item (e.g., individual O&M expense, tax expense, or revenue credit) incurred anytime between the beginning of the Prior Year and the September 30 immediately preceding the Annual Update filing (i.e., a 21 month window) is a one-time item that will not recur in such Rate Year. Individual items shall not be aggregated for purpose of determining a discrete cost of service item. The discrete cost of service item must amount to at least 3% of the Base TRR in such Annual Update filing in order for a Cost Adjustment to be included as a component of the Base TRR. The Cost Adjustment shall be handled as follows:

a) 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. For example, if the discrete cost of service item is a $100 million one-time property tax refund (a negative item) received during 2012 but which will not recur during 2014, + $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. If the discrete cost of

[1] Attachment 2 consists of thirty-four (34) individual Schedules. All references in the Formula Rate Protocols ("Protocols") to Schedules refer to Schedules in the Formula Rate Spreadsheet. The Formula Rate Spreadsheet and Formula Rate Protocols together comprise the "Formula Rate." The formula rate that was in effect from January 1, 2012 through December 31, 2017 pursuant to Docket No. ER11-3697 shall be referred to herein as the "Original Formula Rate", and the formula rate that went into effect on January 1, 2018 pursuant to Docket No. ER18-169, through the effective date of this Formula Rate shall be referred to herein as the "Second Formula Rate".

service item is a $100 million one-time O&M cost (a positive item) incurred during 2012 that will not recur in 2014, - $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. Both examples assume the 3% threshold is met.

b) If the discrete cost of service item occurred between January 1 and September 30 of the year in which the Annual Update filing is submitted to FERC (i.e., the year before the upcoming Rate Year), then the Cost Adjustment component of the Base TRR shall be an amount with the same magnitude and the same sign as the discrete cost of service item. For example, if the discrete cost of service item is a $100 million one-time property tax refund (a negative item) received during the first nine months of 2013 but which will not recur during 2014, - $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. If the discrete cost of service item is a $100 million one-time O&M cost (a positive item) incurred during the first nine months of 2013 that will not recur in 2014, + $100 million will be included as a Cost Adjustment component of the Base TRR in the Annual Update for the 2014 Rate Year. Both examples assume the 3% threshold is met.

If SCE includes a Cost Adjustment in its Base TRR, SCE shall include with its Annual Update an explanation of its belief that the discrete cost of service item that is the subject of such Cost Adjustment will not recur in the upcoming Rate Year.

The Wholesale Base TRR is equal to the Base TRR adjusted as follows (as set forth in Schedule 25): (1) Uncollectibles Expense is not included in the Wholesale Base TRR; (2) the Wholesale Rate Base Adjustment and associated Wholesale Expense Difference is included in the Wholesale TRR; (3) EEI dues and EPRI dues are excluded from the Wholesale Base TRR; and (4) Franchise Fees Expense included in the Wholesale Base TRR is lower than that included in the Base TRR due to the Franchise Fee Factor being applied to a lower Base TRR.

2. TERM OF THE FORMULA RATE

The Formula Rate shall become effective on the date the Commission determines~~January 1, 2018~~, and SCE's Base TRR shall be subject to true up beginning on that date in accordance with these Protocols. Retail and Wholesale transmission rates shall become effective on the date the Commission determines~~January 1, 2018~~, and shall be redetermined annually in accordance with these Protocols and the Formula Rate Spreadsheet. The Formula Rate will remain in effect without termination unless and until SCE files pursuant to Section 205 of the Federal Power Act to replace the Formula Rate with a successor transmission rate mechanism and the Commission accepts such successor transmission rate mechanism. This Formula Rate shall remain in effect until the date that the successor rate mechanism filing is made effective by the Commission.

3. PROCEDURES FOR UPDATING THE BASE TRR

For as long as this Formula Rate is in effect, SCE shall update its Base TRR for the upcoming Rate Year[2] according to the timeline and procedures described in this Section. A summary of the procedures for updating the Base TRR is set forth in the following table:

Event	Date
Posting Date of Draft Annual Update	June 15
Start of Information Requests	June 15
Draft Annual Update Conference	June 15 – July 15
End of Information Requests	November 1
Annual Update filed with FERC	December 1
Rate Goes into Effect	January 1

a) Draft Annual Update

On or before June 15 of each year, SCE will post to its website (www.sce.com) its Draft Annual Update and will provide electronic notice of such posting to the Service List.[3] The Draft Annual Update shall set forth the Base TRR for the upcoming Rate Year, and shall include populated versions of all Schedules comprising the Formula Rate in their native format with all formulas and links intact. In addition to the foregoing, the Draft Annual Update shall include the following:

1) All workpapers used in the calculation of the Base TRR. The workpapers shall be provided in their native format, with all formulas and links intact.

2) The Plant Study described in Section 9 of the Protocols in native format with all formulas and links intact, along with all workpapers prepared in support of the plant study, and a description of any changes in the methodology used to perform the Plant Study as compared with the Prior Year's Annual Update.

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[2] "Rate Year" shall mean the twelve consecutive month period of January 1 through December 31 that corresponds to the year for which charges are assessed under the Formula Rate.

[3] The "Service List" includes (1) any state regulatory agency with jurisdiction over the rates, charges or services of SCE; (2) any person or entity admitted as a party to this Formula Rate proceeding; and (3) any person or entity admitted as a party in any Annual Update proceeding filed by SCE in accordance with these Protocols. For purposes of communications with parties on the Service List, SCE will include the individuals on the service list in the Docket in which this Formula Rate is filed, and parties that are admitted in future FERC proceedings involving Formula Rate Annual Updates. Any references to a "party" in these Protocols shall mean any party to the Docket in which this Formula Rate is filed and any party admitted to future FERC proceedings involving Formula Rate Annual Updates.

3) Workpapers supporting the inputs that appear in Schedule 27 in equivalent form to the workpapers provided in FERC Docket No. ER11-3697, Volume 4, Workpapers for Exhibit SCE-600, pages 1-268.

4) Workpapers that demonstrate the historical corporate overhead expenses recorded for ISO projects by Project Identification Number (PIN) that closed in the prior year and have accumulated ISO project costs greater than $5 million.

5) Workpapers that demonstrate the derivation of the AFUDC rates applicable to all projects in the prior year.

6) Workpapers supporting the forecasted gross plant expenditures shown on Schedule 16.

7) A statement that identifies each ISO project (PIN) with total direct expenditures (recorded and forecast) greater than $5 million projected to go into rate base during the forecast period. The statement will also include the monthly budgeted direct expenditures, to the extent such currently projected costs are shown on the most recent applicable SCE budget documents, and the total project cost of each project.

8) Workpapers showing the beginning of year and end of year outstanding network upgrade credits, as well as interest on network upgrade credits that is recorded in Account 252 listed by entity due those credits. The workpapers shall be provided in equivalent form to the workpapers entitled "Workpapers for Exhibit SCE-800" provided by SCE in FERC Docket No. ER11-3697.

9) Workpapers showing forecast period incentive Construction Work in Progress ("CWIP") projects by PIN and by month that support the values in Schedule 10 at lines 29-70 in equivalent form to the workpapers provided in FERC Docket No. ER11-3697, Volume 3, Workpapers for Exhibit SCE-500, pages 149-175.

10) A description of any Material Accounting Changes contained in the Draft Annual Update.[4]

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[4] "Material Accounting Changes" shall mean any material change that affects SCE's transmission rates as follows: ~~in SCE's~~ (i) accounting policies and practices from those in effect for the Prior Year upon which the immediately preceding Annual Update was based, including those resulting from any new or revised accounting guidance from the Financial Accounting Standards Board;~~,~~ or (ii) internal corporate cost allocation policies or practices in effect for the Prior Year ~~from those policies and/or practices in effect for the Prior Year~~ upon which the immediately preceding Annual Update was based; or (iii) income tax elections from those in effect for the Prior Year upon which the immediately preceding Annual Update was based; or (iv) cost allocation policies between EIX, SCE, and subsidiaries of either, from those in effect for the Prior Year upon which the immediately preceding Annual Update was based. Additionally, a Material Accounting Change shall also include any: (i) initial implementation of an accounting standard; or (ii) initial implementation of accounting practices for unusual or unconventional items where the Commission has not provided specific accounting direction.

11) A workpaper describing the nature and amount of each project/activity, the costs of which are booked to Account 930.2 and which are recovered under the Formula Rate. 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).

12) A workpaper identifying each discrete A&G cost item that has been excluded from Schedule 20 of the Formula Rate (including both "positive exclusions" and "negative exclusions"), together with a summation of such items by account.

13) A description of any facilities SCE projects will change classification between CPUC and CAISO jurisdictions through the Rate Year. This description should include an estimated date for when the project will change classification, the reason for the classification change, and the proposed future rate recovery (*i.e.*, whether through FERC or CPUC rates).

b) Draft Annual Update Conference

SCE will provide notice to parties on the Service List of a one-day meeting, to take place on or before July 15 of each year, to discuss the Draft Annual Update. By mutual agreement of SCE and the parties on the Service List, such a meeting may take place in-person, via telephone, or video-conference. SCE shall make appropriate personnel available for such meeting. Additional meetings to discuss the Draft Annual Update shall be scheduled as SCE and the parties on the Service List may mutually agree.

c) Information Requests

1) At any time from June 15 until November 1, parties on the Service List may submit reasonable information requests to SCE regarding the Draft Annual Update.

2) SCE shall make a good faith effort to respond to information requests in writing within ten (10) business days of receipt. Alternatively, if SCE in good faith believes that the information request is unreasonable, SCE may object to the request. SCE shall contemporaneously provide copies of all responses to all parties on the Service List that have indicated to SCE that they wish to receive such copies. If SCE objects to an information request, then SCE shall make a good faith effort to provide its objections within ten (10) business days of receipt of the information requests to the party serving the request. SCE shall include in its objection the basis for the objection. SCE and the party serving the information request on SCE will work cooperatively and in good

faith to resolve any questions, objections, or disputes relating to the information requests.

3) Responses to information requests shall not be designated as settlement communications or produced under the Commission's rules and regulations governing settlements, unless provided as a privileged settlement communication in a Commission proceeding being conducted under the Commission's settlement rules. SCE may mark materials provided in response to an information request as Protected Materials in accordance with Exhibit A to the Protocols. To the extent an information request response calls for the production of Protected Materials, SCE will only provide such materials to the parties with whom it has entered into a non-disclosure agreement that is included in Exhibit A.

4) To the extent SCE and any interested party(ies) are unable to resolve disputes related to information requests submitted in accordance with these Protocols, SCE or any interested party may petition the FERC to appoint an Administrative Law Judge as a discovery master. Neither SCE nor any interested party shall object to a request for a Discovery Master. The discovery master shall have the power to issue orders to resolve discovery disputes, as appropriate, in accordance with these Protocols and consistent with the FERC's discovery rules. The discovery master's orders shall be subject to appeal to the Commission and to the courts to the same extent and under the same rules as would be applicable to an Initial Decision issued under Rule 708 of the Commission's Rules of Practice and Procedure. In the event the Commission establishes hearing procedures for an Annual Update, the discovery master's responsibilities shall be transferred to the Presiding Judge for such hearing effective upon his or her appointment.

d) Annual Update

1) On or before December 1 of each year, SCE shall file with the Commission its Annual Update setting forth the Base TRR and associated rates for the upcoming Rate Year. It is expressly intended by these Protocols that the Commission will issue public notice of the Annual Update inviting public comment, and SCE shall request in its Annual Update filing that the Commission issue public notice of the Annual Update inviting public comment.

2) SCE shall identify in the Annual Update any corrections or other changes to the Draft Annual Update, and shall provide an explanation of the reason for the changes. SCE shall also include in the Annual Update any changes to the Draft Annual Update that it and any other party have agreed upon as of November 15.

3) The Annual Update shall not modify the Formula Rate or subject the Formula Rate to modification, and shall not constitute a rate change filing under Section 205 of the Federal Power Act. Any party may challenge the justness and reasonableness of SCE's implementation of its Formula Rate with respect to: (a) whether SCE has properly and reasonably applied the Formula Rate Spreadsheet and the procedures in these Protocols; (b) whether the costs to be recovered have been accurately stated, properly recorded and accounted for pursuant to applicable FERC accounting practices and procedures; (c) whether the costs to be recovered through the Base TRR and associated rates have been or will be prudently incurred; (d) whether SCE's projections have been reasonably made; (e) whether its calculation methodologies are consistent with the Formula Rate; (f) whether SCE has made the required filings under Section 8(a) of these Protocols to reflect any intervening change(s) to the Uniform System of Accounts or FERC Form 1; and (g) whether any Material Accounting Changes are reasonable and consistent with the Uniform System of Accounts.

4) The Base TRR set forth in the Annual Update and associated rates shall be effective on January 1 of the upcoming Rate Year.

5) Any party may comment on or protest the Annual Update. Any party may request that FERC establish hearing and/or settlement procedures regarding an Annual Update, and all parties reserve their rights to oppose such requests on their merits, but may not object to such requests on the basis that hearing and/or settlement procedures are prohibited by these Protocols or the Formula Rate Spreadsheet. Nothing in these Protocols shall act as a bar to a party raising an issue in comments or in protests to the Annual Update that it has not raised in a prior Annual Update proceeding (including pre-filing phases of such proceeding) or with respect to which it has not previously exercised its rights under the Federal Power Act. It is expressly intended by these Protocols that FERC issue an order taking action, assuming any action is requested, on the Annual Update if protests and/or comments on the Annual Update are filed.

6) In any Annual Update proceeding, SCE shall bear the burden, consistent with Section 205 of the Federal Power Act, of showing the justness and reasonableness of the implementation of its Formula Rate by demonstrating that: (a) it has properly and reasonably applied the Formula Rate Spreadsheet and the procedures in these Protocols; (b) the costs to be recovered have been accurately stated, properly recorded and accounted for pursuant to applicable FERC accounting practices and procedures; (c) its projections have been reasonably made; (d) its calculation methodologies are consistent with the Formula Rate; and (e) any Material Accounting Changes are reasonable and consistent with the Uniform System of Accounts; Nothing herein is intended to alter the burden of proof applied by the Commission with respect to prudence.

7) SCE will make any revisions to the Base TRR and associated rates that are required by a final[5] Commission order with respect to each Annual Update. Unless otherwise ordered by the Commission, such revisions shall be effective as of the first day of the applicable Rate Year and shall be reflected, with interest calculated pursuant to the interest rate in Section 35.19a of the Commission's regulations, in the next subsequent Annual Update as a component of the True Up Adjustment. If the term of the Formula Rate is expiring so that there will be no future Annual Update, SCE shall include the TRR difference in the Final True Up Adjustment.

8) 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 that affected the True Up TRR calculated in that Annual Update, including but not limited to filed corrections to its FERC Form 1 that affect inputs to the Formula Rate, or errors in other input data used in determining the True Up TRR, SCE shall promptly serve notice to the Commission in the docket of the affected Annual Update that SCE intends to file an Amended Annual Update, with a brief description of the errors to be corrected in such filing. SCE shall additionally notify the entities that have participated in SCE's Annual Update filings of the errors and the upcoming Amended Annual Update. The Amended Annual Update shall:

    i recalculate the True Up TRR for all affected Prior Years;

    ii compare, on a monthly basis, the difference between the initial incorrect True Up TRR and the revised correct True Up TRR; and

    iii determine the cumulative amount of the difference in (ii), including interest calculated pursuant to the interest rate in 18 C.F.R. § 35.19a.

    The difference in (iii) shall be included as an additional component to SCE's True Up Adjustment in the subsequent Annual Update as a One Time True Up Adjustment in accordance with the Formula Rate.

    If the difference in (iii) would not result in an increase to the True-Up TRR of more than $1 million, however, then SCE need not submit to the Commission an Amended Annual Update, as described above, but may include the difference in (iii) in its Draft Annual Update, or, if the error is discovered after the posting of a Draft Annual Update on June 15, in an amended Draft Annual Update posted on SCE's website no later than October 31.

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[5] All references in these Protocols to Commission orders or actions refer to the final form of such orders or actions (in accordance with the Federal Power Act and applicable Commission regulations, including without limitation Commission regulations with respect to a stay of a Commission order upon rehearing and/or an appeal), including as they may be modified as a result of a request for rehearing or Court appeal.

In the event that SCE has identified multiple input errors, SCE shall identify each such error and its correction individually. The amount proposed to be included in an Amended Annual Update, a Draft Annual Update, or an amended Draft Annual Update as a One Time True Up Adjustment shall be subject to scrutiny through the information exchange process and annual update procedures described in this Section 3.

4. THE ANNUAL TRUE UP ADJUSTMENT AND THE FINAL TRUE UP ADJUSTMENT

The Annual True Up Adjustment component of the Base TRR ensures that during the time the Formula Rate is in effect, SCE will recover its actual costs of owning and operating its ISO transmission facilities, as defined by the True Up TRR. The Annual True Up Adjustment is calculated for each Annual Update for the previous calendar year (the "Prior Year"), if the Formula Rate, or a previous formula rate, was in effect during some or all of that year, through the following steps:

a) Calculate SCE's actual costs during the Prior Year, as measured by the "True Up TRR." The True Up TRR, as defined in the Formula Rate, is equal to the Prior Year TRR as defined in the Formula Rate, except that all of the Rate Base components used in the True Up TRR are based on 13-month average values or beginning-of-year and end-of-year average values.

b) Attribute the True Up TRR to each month of the Prior Year as specifically defined in the Formula Rate.

c) Determine SCE's actual retail base transmission revenues attributable to the Formula Rate on a monthly basis for each month of the Prior Year, in accordance with the Formula Rate.

d) Compare SCE's monthly True Up TRR to SCE's monthly actual retail base transmission revenues. Each monthly difference shall be cumulated, including interest calculated on a monthly basis using the interest rate specified in the regulations of the Commission at 18 C.F.R § 35.19a, through the end of the Prior Year, in accordance with the Formula Rate to determine a "Shortfall or Excess Revenue in the Prior Year". The "Shortfall or Excess Revenue in the Prior Year" shall also include the "Shortfall or Excess Revenue in the Prior Year" from the previous Annual Update, as specifically included in Schedule 3 of the Formula Rate Spreadsheet, Schedule 3, Line 11, and any applicable One Time Adjustments.

e) As stated in Section 6 below, the True Up Adjustment included in the Base TRR effective January 1, 2018 shall include the Final True Up Adjustment for the 2016 year calculated pursuant to the Original Formula Rate. The Final True Up Adjustment for the 2017 year calculated pursuant to the Original Formula Rate shall be included in the True Up Adjustment for the Annual Update submitted by December 1, 2018. The True Up Adjustment included in the Base TRR effective January 1, 2020 shall include the Final True Up Adjustment for the 2018 year calculated pursuant to the Second Formula Rate. The True Up Adjustment included in the Base TRR effective January 1, 2021 shall include the Final True Up Adjustment for the portion of the 2019 year for which the Second Formula

Rate was in effect, calculated pursuant to the Second Formula Rate.

In the event that this Formula Rate terminates, 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 on December 31, 2030, SCE will determine a Final True Up Adjustment in 2031 for calendar year 2030. 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 this 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.

5. THE INCREMENTAL FORECAST PERIOD TRR

The Incremental Forecast Period TRR ("IFPTRR"), calculated in Schedule 2 (Incremental Forecast Period TRR) of the Formula Rate Spreadsheet, is a component of SCE's Base TRR that represents the amount of transmission revenue requirement that SCE anticipates during the upcoming Rate Year that is incremental to that reflected in the Prior Year TRR as a result of additions of plant in service (identified in Schedule 16 (Plant Additions) of the Formula Rate) and/or CWIP expenditures (identified in Schedule 10 (CWIP) of the Formula Rate) to Rate Base. The IFPTRR shall be calculated in accordance with the Formula Rate.

6. TRANSITION OF THE ORIGINAL AND SECOND FORMULA RATES TO SUCCESSOR~~THE~~ FORMULA RATES

Pursuant to Section 4 of the Formula Rate Protocols for the Original Formula Rate, SCE is entitled and required to reflect the amount of any Final True Up Adjustment from the Original Formula Rate for the 2016 and 2017 years in its successor transmission rates. This Section 6 ensures that this requirement from the Original Formula Rate is implemented accurately.

The Formula Rate Base TRR and associated rates for the Rate Years 2018 and 2019 shall reflect a True Up Adjustment that is based on a True Up TRR for the years 2016 and 2017 respectively calculated pursuant to the Original Formula Rate. This shall be implemented in the rate filing for the 2018 Rate Year and the Annual Update for the 2019 Rate Year by including as a "One Time Adjustment" any difference in the True Up TRR for the Prior Years of 2016 and 2017 calculated under this Formula Rate and the

True Up TRR amounts calculated pursuant to the Original Formula Rate in Column 4 of Schedule 3 of the Formula Rate Spreadsheet. The One Time Adjustment included in the 2018 Rate Year filing will reflect the difference between the 2016 year True Up TRR

calculated pursuant to the~~is~~ Second Formula Rate and the Original Formula Rate. The Annual Update for the 2019 Rate Year will reflect the difference between the 2017 year True Up TRR calculated pursuant to the~~is~~ Second Formula Rate and the Original Formula Rate. The 2017 True Up TRR calculated pursuant to the Original Formula Rate shall include an amount of Excess Deferred Income Taxes for year-end 2017 relating to the 2017 Tax Cuts and Jobs Act as a component of the calculation of Accumulated Deferred Income Taxes ("ADIT") in Schedule 9 of the Formula Rate Spreadsheet created as a result of the change in the Federal Income Tax Rate. Such amount shall be included along with Account 190, 282, and 283 amounts in the calculation of End-of-Year "Total Accumulated Deferred Income Taxes" on Line 4 of Schedule 9. ~~In the event that this Formula Rate does not become effective until after January 1, 2018, so that the Original Formula Rate remained in effect throughout part or all of 2018, the calculation of the True Up TRR for 2018 shall be based on a weighted average of the True Up TRRs calculated pursuant to the Original Formula Rate and this Formula Rate, with the weighting being based on the number of days during the 2018 year each was in effect (and any years after 2018 will be treated similarly). The One Time Adjustment for any such years with two formula rates in effect shall be calculated based on the difference between the weighted average True Up TRRs and the True Up TRR calculated pursuant to this Formula Rate. Additionally, the True Up Adjustment submitted in the filing for Rate Year 2018 shall include as a One Time Adjustment any "Cumulative Excess or Shortfall in Revenue with Interest" through the end of 2015 calculated pursuant to the Original Formula Rate, as reflected in SCE's Annual Update Filing submitted in ER11-3697 on November 30, 2016, Schedule 3, Line 34, Column 8. The 2018 Rate Year filing and the 2019 Annual Update shall include as a workpaper a calculation of these One Time Adjustments.~~

Additionally, any transition from one formula rate to its successor formula rate shall ensure that the True Up TRRs for any years for which a previous formula rate or formula rates were in effect during all or part of that year are calculated utilizing the formula rate, or formula rates, that were in effect during the year being trued up. This shall be implemented through a "One Time Adjustment" reflecting the difference between the True Up TRR calculated using the Formula Rate in effect at the time of the Annual Update, and the True Up TRR calculated pursuant to the formula rate, or formula rates, that were in effect during the year being trued up. In the event that any year being trued up has two or more formulas in effect during that year, the True Up TRR for that year shall be based on a weighted average of the True Up TRRs calculated pursuant to the formula rates in effect that year, with the weighting being based on the number of days during the year that each was in effect. Any Annual Update which includes a Final True Up Adjustment for a previous year shall include a workpaper with a calculation of the associated One Time Adjustments.

7. DEPRECIATION RATES

Depreciation rates for Transmission Plant, Distribution Plant, General Plant, and Intangible Plant shall be as stated in the Formula Rate Spreadsheet.

8. REVISIONS TO CERTAIN FORMULA RATE PROVISIONS

SCE will be required to make single-issue Section 205 filings to change the Formula Rate as provided in Section 8, parts (a) through (e). In addition to the single-issue filings provided for in this Section 8 and subject to the limitations set forth in Section 11, SCE may make Section 205 filings that present only a single issue or limited discrete issues for consideration by the Commission, *i.e*., proposing to change any one or more elements of its Formula Rate. Such filings shall not be governed by the provisions of this Section 8, and the parties and SCE reserve their rights with respect to any such filing.

In a proceeding commenced by such a single-issue Section 205 filing under Section 8, parts (a) and (b), the sole issues that can or shall be addressed are whether the changes proposed by SCE are consistent with these Protocols and are just and reasonable.

In a proceeding commenced by a single-issue filing under Section 8, part (c), the sole issues that can or shall be addressed are whether the changes proposed by SCE are just and reasonable and correctly implement the applicable California Public Utilities Commission ("CPUC") order.

In a proceeding commenced by a single-issue filing under Section 8, parts (d) and (e), the sole issue that can or shall be addressed is whether the changes proposed by SCE correctly implement the applicable CPUC order.

The proceedings commenced in response to the filings described in this Section shall not include or allow for consideration or examination of any other aspects of the Formula Rate or other issues associated with the Formula Rate, except to the extent that the proposed changes directly impact other Formula Rate components that are not the subject of the single-issue filing. All parties will have all applicable rights under the Federal Power Act and FERC's regulations with respect to such single-issue Section 205 filings, except as limited by this Section 8.

a) SCE will make a single-issue Section 205 filing to update the references in the Formula to reflect any changes to the format and/or content of the FERC Form 1 or the Uniform System of Accounts that affect the calculations set forth in the Formula in the event that a Commission order revises the format and/or content of the FERC Form 1 or the Uniform System of Accounts. This filing shall be submitted within sixty days of the implementation of any FERC decision to revise the FERC Form 1 or the Uniform System of Accounts, and shall be effective on the date of the revisions to the FERC Form 1 or Uniform System of Accounts, as applicable.

b) With respect to Post-Retirement Benefits Other than Pensions ("PBOPs"), the Formula Rate identifies an Authorized PBOPs Expense Amount in Note 3 on Schedule 20 (Administrative and General Expenses)~~, which is initially stated as $40,171,333~~. ~~Beginning in 2019,~~ SCE shall make a single-issue Section 205 filing by April 1 of each year to revise the Authorized PBOPs Expense Amount, seeking an effective date of January 1 of the year of the filing.

c) 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, as set forth in this Section, between January 1 and March 1 of the year following the year that the CPUC order became effective.

d) SCE will make a single-issue Section 205 filing to revise Schedule 33 of the Formula Rate determination of retail transmission rates to reflect any change in Rate Groups, Rate Schedules, or the design of retail rates applicable to each Rate Schedule subsequent to any final CPUC order that affects these aspects of retail transmission rates. SCE will make such a filing only if and when the change in Rate Groups, Rate Schedules, or the design of retail rates cannot otherwise be reflected through the normal operation of the Formula Rate. In the single-issue Section 205 filing to the Commission, SCE will propose revisions to Schedule 33 of the Formula Rate that conform to the CPUC order. SCE will make a filing under this Section 8(d) by the later of either the filing date for the next Annual Update following the CPUC ruling or sixty days after the CPUC ruling.

e) 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.

9. DETERMINATION OF AMOUNT OF TRANSMISSION PLANT - ISO AND DISTRIBUTION PLANT - ISO

SCE shall perform for the Prior Year a study ("Plant Study") to determine:

- The amount of plant classified as Transmission in SCE's annual FERC Form 1 filing that is under the Operational Control of the ISO. Such amount shall be called Transmission Plant - ISO; and
- The amount of plant classified as Distribution in SCE's annual FERC Form 1 filing that is under the Operational Control of the ISO. Such amount shall be called Distribution Plant - ISO.

The Plant Study determination of Transmission Plant - ISO and Distribution Plant - ISO will correspond to the end-of-year plant values for transmission and distribution published in SCE's FERC Form 1, and also shall be based on actual end-of-year ISO Operational Control of facilities. SCE will identify in the Plant Study major transmission facilities that have moved to or from ISO Operational Control in the Prior Year. Additionally, in submitting its future CPUC General Rate Case applications, SCE shall exclude from its CPUC-jurisdictional cost of service forecast, the cost of transmission and distribution facilities that SCE projects will be under the Operational Control of the ISO during the test year.

The methodology used in the Plant Study to determine Transmission Plant - ISO and Distribution Plant - ISO shall be as follows:

a) For each Transmission account 350-359 and Distribution account 360-362, identify the year-end recorded gross plant amount.

b) For Transmission accounts 350-359 and Distribution accounts 360-362, classify the assets by each location into one of the following categories:

   1) All ISO: All Transmission or Distribution assets at the location are under the Operational Control of the ISO.

   2) Non-ISO: No Transmission or Distribution assets at the location are under the Operational Control of the ISO.

   3) Mixed ISO and Non-ISO Substation: The Transmission or Distribution substation location has a mixture of assets under the Operational Control of the ISO and assets that are not under the Operational Control of the ISO.

   4) Mixed ISO and Non-ISO Line: Transmission line locations that have a mixture of assets under the Operational Control of the ISO and assets that are not under the Operational Control of the ISO that need to be analyzed using the Transmission Line methodology.

   5) Other: Assets for which there is not sufficient data to categorize into one of the above categories.

For all plant costs classified as (1) “All ISO”, classify all such plant costs as Transmission Plant - ISO or Distribution Plant - ISO, as appropriate. For all plant costs classified as (2) “Non-ISO”, classify none of such plant costs as “Transmission Plant - ISO” or “Distribution Plant - ISO.”

For all plant costs classified as (3) “Mixed ISO and Non-ISO Substation,” perform an analysis of plant costs based on individual components of the substation. Component plant costs that are under the Operational Control of the ISO shall be attributed to either Transmission Plant - ISO or Distribution Plant - ISO, as appropriate. Component plant costs that are not under the Operational Control of the ISO shall not be attributed to either Transmission Plant - ISO or Distribution Plant - ISO. Dual Use assets (supporting both ISO and non-ISO plant) shall be allocated to Transmission Plant - ISO or Distribution Plant - ISO based on the percentage of ISO assets for the location.

For all plant costs classified as (4) “Mixed ISO and Non-ISO Line,” apply the methodology set forth in Section 9(c) below to classify such costs.

For all plant costs classified as (5) “Other” in a location, classify such costs as Transmission Plant - ISO or Distribution Plant - ISO in proportion to the total percentage of Transmission Plant - ISO or Distribution Plant - ISO determined in parts (1) through (4) for that location.

c) Transmission line costs (including any amounts in accounts 350, 352, and 353) required to be analyzed under the Transmission Line methodology pursuant to (b) (4) above shall be attributed to Transmission Plant - ISO according to the following methodology:

   1) For each location, determine the total line miles and total line miles that are under the Operational Control of the ISO. Determine the percent of total line miles under the Operational Control of the ISO to total line miles at that location. This calculation shall be done separately for overhead and underground facilities in the location.

   2) Determine the amount of Transmission Plant - ISO by applying the percent determined in (1) to the appropriate plant costs by account at that location.

   SCE shall present a summary of the Plant Study for the Prior Year in each annual Draft Annual Update, in accordance with the Formula Rate.

10. DETERMINATION OF AMOUNT OF ISO OPERATION AND MAINTENANCE EXPENSE

SCE shall annually determine the amount of recorded Transmission and Distribution Operation and Maintenance ("O&M") expenses that is attributable to facilities under the Operational Control of the ISO ("ISO O&M Expense"). The method used to determine ISO O&M Expense shall be to allocate total recorded O&M Expenses as stated in FERC Form 1 based on specific allocation factors applied to the expenses recorded to the O&M accounts set forth in Schedule 19 of the Formula Rate Spreadsheet.

In the event that SCE experiences an extraordinary event, resulting in costs otherwise recoverable through the Formula Rate in a year to be recorded to Account 435 (Extraordinary Deductions) of the Uniform System of Accounts, SCE shall recover the full amount of such Account 435 costs, including any expenses or return on capital, in accordance with the Commission Order authorizing such recovery.

11. RESERVATION OF RIGHTS

a) Nothing in these Protocols shall be deemed to limit in any way the right of any party admitted as an intervenor to this Formula Rate proceeding or admitted as an intervenor to any future proceeding involving an Annual Update to file a request for relief under any applicable provision of the FPA and/or the Commission's regulations or participate in Annual Update proceedings.

b) Nothing in these Protocols shall be deemed to limit in any way SCE's right to file unilaterally, pursuant to Section 205 of the FPA and the regulations thereunder, to seek to change or cancel the Formula Rate, or to submit any other request for relief under any applicable provision of the FPA and/or the Commission's regulations.

c) The party filing a proposed change to the Formula Rate Spreadsheet or Formula

Rate Protocols under Section 205 or 206 of the FPA bears the standard burdens associated with such a filing.

12. USE OF INFORMATION

Information produced pursuant to these Protocols may be used in any proceeding concerning the Formula Rate Spreadsheet, the Protocols, or the Annual Update; provided, however, that to the extent that any information provided pursuant to these Protocols has been designated and provided as Protected Materials, subject to the provisions of Exhibit A to these Protocols, the use of such information shall be governed by Exhibit A.

This section shall not apply to any information produced in the course of Commission-established settlement proceedings pursuant to the Commission's rules and regulations governing settlement.

EXHIBIT A

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PROTECTIVE ORDER APPLICABLE TO INFORMATION PRODUCED BY SOUTHERN CALIFORNIA EDISON COMPANY PURSUANT TO THE FORMULA RATE PROTOCOLS

1. This Exhibit (hereinafter referred to as the "Protective Order") shall govern the use of all Protected Materials produced by, or on behalf of, Southern California Edison Company ("SCE") pursuant to the SCE Formula Rate Protocols.

2. This Protective Order applies to the following two categories of materials: (A) A Participant may designate as protected those materials which customarily are treated by that Participant as sensitive or proprietary, which are not available to the public, and which, if disclosed freely, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and (B) A Participant shall designate as protected those materials which contain critical energy infrastructure information, as defined in 18 CFR§ 388.113(c)(1) ("Critical Energy Infrastructure Information").

3. Definitions -- For purposes of this Order:

(a) The term "Participant" shall mean a Participant as defined in 18 CFR § 385.102(b).

(b) (1) The term "Protected Materials" means (A) materials (including depositions) provided by a Participant in response to discovery requests and designated by such Participant as protected; (B) any information contained in or obtained from such designated materials; (C) any other materials which are made subject to this Protective Order by the Presiding Administrative Law Judge appointed upon the Annual Update being set for hearing and/or settlement procedures or by the Discovery Master appointed pursuant to the Formula Rate Protocols (both referred to herein as the "Presiding Judge"), by the Commission, by any court or other body having appropriate authority, or by agreement of the Participants; (D) notes of Protected Materials; and (E) copies of Protected Materials. The Participant producing the Protected Materials shall physically mark them on each page as "PROTECTED MATERIALS" or with words of similar import as long as the term "Protected Materials" is included in that designation to indicate that they are Protected Materials. If the Protected Materials contain Critical Energy Infrastructure Information, the Participant producing such information shall additionally mark on each page containing such information the words "Contains Critical Energy Infrastructure Information B Do Not Release".

(2) The term "Notes of Protected Materials" means memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses materials described in Paragraph 3(b)(1). Notes of Protected Materials are subject to the same restrictions provided in this order for Protected Materials except as specifically provided in this order.

(3) Protected Materials shall not include (A) any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be protected by such agency or court, or (B) information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Order. Protected Materials do include any information or document contained in the files of the Commission that has been designated as Critical Energy Infrastructure Information.

(c) The term "Non-Disclosure Certificate" shall mean the certificate annexed hereto by which Participants who have been granted access to Protected Materials shall certify their understanding that such access to Protected Materials is provided pursuant to the terms and restrictions of this Protective Order, and that such Participants have read the Protective Order and agree to be bound by it. All Non-Disclosure Certificates shall be served on all parties on the Service List, as defined in the SCE Formula Rate Protocols.

(d) The term "Reviewing Representative" shall mean a person who has signed a Non-Disclosure Certificate and who is:

(1) Commission Trial Staff;

(2) an attorney who has made an appearance for a Participant;

(3) attorneys, paralegals, and other employees associated with an attorney described in Subparagraph (2);

(4) an expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for or testifying in connection with the Annual Update for which the information was requested;

(5) a person designated as a Reviewing Representative by order of the Presiding Judge or the Commission; or

(6) employees or other representatives of Participants with significant responsibility for SCE's Formula Rate.

4. Protected Materials shall be made available under the terms of this Protective Order only to Participants and only through their Reviewing Representatives as provided in Paragraphs 7-9.

5. Protected Materials shall remain available to Participants until the date that any Commission proceeding relating to the Protected Material is concluded and no longer subject to judicial review. If requested to do so in writing after that date, the Participants shall, within fifteen days of such request, return the Protected Materials (excluding Notes of Protected Materials) to the Participant that produced them, or shall destroy the materials, except that copies of filings, official transcripts and exhibits in this proceeding that contain Protected Materials, and Notes of Protected Material may be retained, if they are maintained in accordance with Paragraph 6, below. Within such time period each Participant, if requested to do so, shall also submit to the producing Participant an affidavit stating that, to the best of its knowledge, all Protected Materials and all Notes of Protected Materials have been returned or have been destroyed or will be maintained in accordance with Paragraph 6. To the extent Protected Materials are not returned or destroyed, they shall remain subject to the Protective Order.

6. All Protected Materials shall be maintained by the Participant in a secure place. Access to those materials shall be limited to those Reviewing Representatives specifically authorized pursuant to Paragraphs 8-9. The Secretary shall place any Protected Materials filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination of any claim of privilege. The Commission retains the right to make determinations regarding any claim of privilege and the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff ("Staff"), Staff shall follow the notification procedures of 18 CFR § 388.112 before making public any Protected Materials.

7. Protected Materials shall be treated as confidential by each Participant and by the Reviewing Representative in accordance with the certificate executed pursuant to

Paragraph 9. Protected Materials shall not be used except as necessary under SCE's Formula Rate Protocols, nor shall they be disclosed in any manner to any person except a Reviewing Representative who is engaged in working on SCE's Annual Update for which the information was requested and who needs to know the information in order to carry out such responsibilities. Reviewing Representatives may make copies of Protected Materials, but such copies become Protected Materials. Reviewing Representatives may make notes of Protected Materials, which shall be treated as Notes of Protected Materials if they disclose the contents of Protected Materials.

8. (a) If a Reviewing Representative's scope of employment includes the marketing of energy, the direct supervision of any employee or employees whose duties include the marketing of energy, the provision of consulting services to any person whose duties include the marketing of energy, or the direct supervision of any employee or employees whose duties include the marketing of energy, such Reviewing Representative may not use information contained in any Protected Materials obtained under SCE's Formula Rate Protocols to give any Participant or any competitor of any Participant a commercial advantage.

(b) In the event that a Participant wishes to designate as a Reviewing Representative a person not described in Paragraph 3 (d) above, the Participant shall seek agreement from the Participant providing the Protected Materials. If an agreement is reached that person shall be a Reviewing Representative pursuant to Paragraphs 3(d) above with respect to those materials. If no agreement is reached, the Participant shall submit the disputed designation to the Presiding Judge for resolution.

9. (a) A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Protected Materials pursuant to this Protective Order unless that Reviewing Representative has first executed a Non-Disclosure Certificate; provided, that if an attorney qualified as a Reviewing Representative has executed such a certificate, the paralegals, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. A copy of each Non-Disclosure Certificate shall be provided to counsel for the Participant asserting confidentiality prior to disclosure of any Protected Material to that Reviewing Representative.

(b) Attorneys qualified as Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this order.

10. Any Reviewing Representative may disclose Protected Materials to any other Reviewing Representative as long as the disclosing Reviewing Representative and the receiving Reviewing Representative both have executed a Non-Disclosure Certificate. In the event that any Reviewing Representative to whom the Protected Materials are disclosed ceases to be engaged in working on the Annual Update, as set forth above, or is employed or retained for a position whose occupant is not qualified to be a Reviewing Representative under Paragraph 3(d), access to Protected Materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Order and the certification.

11. Subject to Paragraph 18, the Presiding Administrative Law Judge shall resolve any disputes arising under this Protective Order. Prior to presenting any dispute under this Protective Order to the Presiding Administrative Law Judge, the parties to the dispute shall use their best efforts to resolve it. Any participant that contests the designation of materials as protected shall notify the party that provided the protected materials by specifying in writing the materials the designation of which is contested. This Protective Order shall automatically cease to apply to such materials five (5) business days after the notification is made unless the designator, within said 5-day period, files a motion with the Presiding Administrative Law Judge, with supporting affidavits, demonstrating that the materials should continue to be protected. In any challenge to the designation of materials as protected, the burden of proof shall be on the participant seeking protection. If the Presiding Administrative Law Judge finds that the materials at issue are not entitled to protection, the procedures of Paragraph 18 shall apply. The procedures described above shall not apply to protected materials designated by a Participant as Critical Energy Infrastructure Information. Materials so designated shall remain protected and subject to the provisions of this Protective Order, unless a Participant requests and obtains a determination from the Commission's Critical Energy Infrastructure Information Coordinator that such materials need not remain protected.

12. All copies of all documents reflecting Protected Materials, including the portion of the hearing testimony, exhibits, transcripts, briefs and other documents which refer to Protected Materials, shall be filed and served in sealed envelopes or other appropriate containers endorsed to the effect that they are sealed pursuant to this Protective Order. Such documents shall be marked "PROTECTED MATERIALS" and shall be filed under seal and served under seal upon the Presiding Judge and all Reviewing Representatives who are on the service list. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information - Do Not Release". For anything filed under seal, redacted versions or, where an entire

document is protected, a letter indicating such, will also be filed with the Commission and served on all parties on the service list and the Presiding Judge. Counsel for the producing Participant shall provide to all Participants who request the same, a list of Reviewing Representatives who are entitled to receive such material. Counsel shall take all reasonable precautions necessary to assure that Protected Materials are not distributed to unauthorized persons.

13. If any Participant desires to include, utilize or refer to any Protected Materials or information derived therefrom in testimony or exhibits during a hearing under the SCE Formula Rate Protocols in such a manner that might require disclosure of such material to persons other than reviewing representatives, such participant shall first notify both counsel for the disclosing participant and the Presiding Judge of such desire, identifying with particularity each of the Protected Materials. Thereafter, use of such Protected Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Order shall be construed as precluding any Participant from objecting to the use of Protected Materials on any legal grounds.

15. Nothing in this Protective Order shall preclude any Participant from requesting the Presiding Judge, the Commission, or any other body having appropriate authority, to find that this Protective Order should not apply to all or any materials previously designated as Protected Materials pursuant to this Protective Order. The Presiding Judge may alter or amend this Protective Order as circumstances warrant at any time during the course of this proceeding.

16. Each party governed by this Protective Order has the right to seek changes in it as appropriate from the Presiding Judge or the Commission.

17. All Protected Materials filed with the Commission, the Presiding Judge, or any other judicial or administrative body, in support of, or as a part of, a motion, other pleading, brief, or other document, shall be filed and served in sealed envelopes or other appropriate containers bearing prominent markings indicating that the contents include Protected Materials subject to this Protective Order. Such documents containing Critical Energy Infrastructure Information shall be additionally marked "Contains Critical Energy Infrastructure Information – Do Not Release."

18. If the Presiding Judge finds at any time in the course of a proceeding that all or part of the Protected Materials need not be protected, those materials shall, nevertheless, be subject to the protection afforded by this Protective Order for three (3) business days from the date of issuance of the Presiding Judge's determination, and if the Participant seeking protection files an interlocutory

appeal or requests that the issue be certified to the Commission, for an additional seven (7) business days. None of the Participants waives its rights to seek additional administrative or judicial remedies after the Presiding Judge's decision respecting Protected Materials or Reviewing Representatives, or the Commission's denial of any appeal thereof. The provisions of 18 CFR §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act. (5 U.S.C. § 552) for Protected Materials in the files of the Commission.

19. Nothing in this Protective Order shall be deemed to preclude any Participant from independently seeking through discovery in any other administrative or judicial proceeding information or materials produced under the SCE Formula Rate Protocols under this Protective Order.

20. None of the Participants waives the right to pursue any other legal or equitable remedies that may be available in the event of actual or anticipated disclosure of Protected Materials.

21. The contents of Protected Materials or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with this Protective Order and shall be used only in connection with this (these) proceeding(s). Any violation of this Protective Order and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Protected Materials is provided to me pursuant to the terms and restrictions of the Protective Order under the Southern California Edison Formula Rate Protocols, that I have been given a copy of and have read the Protective Order, and that I agree to be bound by it. I understand that the contents of the Protected Materials, any notes or other memoranda, or any other form of information that copies or discloses Protected Materials shall not be disclosed to anyone other than in accordance with that Protective Order. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: ______________________________
Printed Name: _____________________
Title: ____________________________
Representing:______________________
Date: ____________________________

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	$ -
Incremental Forecast Period TRR	$ -
True-Up Adjustment	$ -
Cost Adjustment	$ -
Base TRR (retail)	$ -

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.

Schedule 1
Base TRR

Southern California Edison Company

Formula Transmission Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction		Value
					-
RATE BASE					
1	ISO Transmission Plant		6-PlantInService, Line 19	$	-
2	General Plant + Electric Miscellaneous Intangible Plant		6-PlantInService, Line 27	$	-
3	Transmission Plant Held for Future Use		11-PHFU, Line 8	$	-
4	Abandoned Plant		12-AbandonedPlant, Line 3	$	-
	Working Capital amounts				
5	Materials and Supplies		13-WorkCap, Line 16	$	-
6	Prepayments		13-WorkCap, Line 36	$	-
7	Cash Working Capital		(Line 66 + Line 67) / 8	$	-
8	Working Capital		Line 5 + Line 6 + Line 7	$	-
	Accumulated Depreciation Reserve Balances				
9	Transmission Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 13, Col. 12	$	-
10	Distribution Depreciation Reserve - ISO	Negative amount	8-AccDep, Line 16, Col. 5	$	-
11	General + Intangible Plant Depreciation Reserve	Negative amount	8-AccDep, Line 26	$	-
12	Accumulated Depreciation Reserve		Line 9 + Line 10 + Line 11	$	-
13	Accumulated Deferred Income Taxes	Negative amount	9-ADIT, Line 5, Col. 2	$	-
14	CWIP Plant		14-IncentivePlant, L 12, Col 1	$	-
15	Other Regulatory Assets/Liabilities		23-RegAssets, Line 14	$	-
16	Unfunded Reserves		34-UnfundedReserves, Line 6	$	-
17	Network Upgrade Credits	Negative amount	22-NUCs, Line 4	$	-
18	Rate Base		L1 + L2 + L3 + L4 + L8 + L12 + L13 + L14+ L15+ L16 + L17	$	-
OTHER TAXES					
19	Sub-Total Local Taxes	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
20	Transmission Plant Allocation Factor		27-Allocators, Line 22		- %
21	Property Taxes		Line 19 * Line 20	$	-
22	Payroll Taxes Expense				
23	FICA		Line 24 + Line 25+ Line 26	$	-
24	Fed Ins Cont Amt -- Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
25	FICA/OASDI Emp Incntv.	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
26	FICA/HIT Emp Incntv.	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
27	CA SUI Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
28	Fed Unemp Tax Act- Current	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
29	CADI Vol Plan Assess	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
30	SF Pyrl Exp Tx - SCE	FF1 _, Row _, Column i	FF1 263 or 263.x (see note to left)	$	-
31	Total Electric Payroll Tax Expense		Line 23 + (Line 27 to Line 30)	$	-
32	Capitalized Overhead portion of Electric Payroll Tax Expense		26-TaxRates, Line 16	$	-
33	Remaining Electric Payroll Tax Expense to Allocate		Line 31 - Line 32	$	-
34	Transmission Wages and Salaries Allocation Factor		27-Allocators, Line 9		- %
35	Payroll Taxes Expense		Line 33 * Line 34	$	-
36	Other Taxes	Note 1	Line 21 + Line 35	$	-

Schedule 1
Base TRR

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	Value
				-
	RETURN AND CAPITALIZATION CALCULATIONS			
	Debt			
37	Long Term Debt Amount		5-ROR-1, Line 13 12	$ -
38	Cost of Long Term Debt		Line 37 * Line 39	$ -
39	Long Term Debt Cost Percentage		5-ROR-3, Line 12 10	- %
	Preferred Stock			
40	Preferred Stock Amount		5-ROR-1, Line 17 16	$ -
41	Cost of Preferred Stock		Line 40 * Line 42	$ -
42	Preferred Stock Cost Percentage		5-ROR-4, Line 9	- %
	Equity			
43	Common Stock Equity Amount		5-ROR-1, Line 23 21	$ -
44	Total Capital		Line 37 + Line 40 + Line 43	$ -
	Capital Percentages			
45	Long Term Debt Capital Percentage		Line 37 / Line 44	- %
46	Preferred Stock Capital Percentage		Line 40 / Line 44	- %
47	Common Stock Capital Percentage		Line 43 / Line 44	- %
			Line 45 + Line 46+ Line 47	- %
	Annual Cost of Capital Components			
48	Long Term Debt Cost Percentage		Line 39	- %
49	Preferred Stock Cost Percentage		Line 42	- %
50	Return on Common Equity	Note 2	SCE Return on Equity	17.62~~10.8~~%
	Calculation of Cost of Capital Rate			
51	Weighted Cost of Long Term Debt		Line 39 * Line 45	- %
52	Weighted Cost of Preferred Stock		Line 42 * Line 46	- %
53	Weighted Cost of Common Stock		Line 47 * Line 50	- %
54	Cost of Capital Rate		Line 51 + Line 52 + Line 53	- %
55	Equity Rate of Return Including Common and Preferred Stock	Used for Tax calculation	Line 52 + Line 53	- %
56	Return on Capital: Rate Base times Cost of Capital Rate		Line 18 * Line 54	$ -
	INCOME TAXES			
57	Federal Income Tax Rate		26-Tax Rates, Line 1	- %
58	State Income Tax Rate		26-Tax Rates, Line 8	- %
59	Composite Tax Rate	= F + [S * (1 - F)]	(L57 + L58) - (L57 * L58)	- %
	Calculation of Credits and Other:			
60	Amortization of Excess Deferred Tax Liability	Note 3		$ -
61	Investment Tax Credit Flowed Through	Note 3		$ -
62	South Georgia Income Tax Adjustment	Note 3		$2,606,000
63	Credits and Other		Line 60 + Line 61+ Line 62	$ -
64	Income Taxes:		Formula on Line 65	$ -
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	$ -

Schedule 1
Base TRR

Southern California Edison Company

Cells shaded yellow are input cells

Formula Transmission Rate

Line		Notes	FERC Form 1 Reference or Instruction	Value
				-
PRIOR YEAR TRANSMISSION REVENUE REQUIREMENT				
	Component of Prior Year TRR:			
66	O&M Expense		19-OandM, Line 91, Col. 6	$ -
67	A&G Expense		20-AandG, Line 23	$ -
68	Network Upgrade Interest Expense		22-NUCs, Line 8	$ -
69	Depreciation Expense		17-Depreciation, Line 70	$ -
70	Abandoned Plant Amortization Expense		12-AbandonedPlant, Line 1	$ -
71	Other Taxes		Line 36	$ -
72	Revenue Credits	Negative amount	21-Revenue Credits, Line 44	$ -
73	Return on Capital		Line 56	$ -
74	Income Taxes		Line 64	$ -
75	Gains and Losses on Trans. Plant Held for Future Use -- Land	Gain negative, loss positive	11-PHFU, Line 10	$ -
76	Amortization and Regulatory Debits/Credits		23-RegAssets, Line 16	$ -
77	Prior Year Incentive Adder		15-IncentiveAdder, Line 14	$ -
78	Total without FF&U		Sum of Lines 66 to 77	$ -
79	Franchise Fees Expense		L 78 * FF Factor (28-FFU, L 5)	$ -
80	Uncollectibles Expense		L 78 * U Factor (28-FFU, L 5)	$ -
81	Prior Year TRR		Line 78 + Line 79+ Line 80	$ -
TOTAL BASE TRANSMISSION REVENUE REQUIREMENT				
	Calculation of Base Transmission Revenue Requirement			
82	Prior Year TRR		Line 81	$ -
83	Incremental Forecast Period TRR		2-IFPTRR, Line 82	$ -
84	True Up Adjustment		3-TrueUpAdjust, Line 30	$ -
85	Cost Adjustment	Note 4		$ -
86	Base Transmission Revenue Requirement (Retail)	For Retail Purposes	L 82 + L 83 + L 84 + L 85	$ -
	Wholesale Base Transmission Revenue Requirement			
87	Base TRR (Retail)		Line 86	$ -
88	Wholesale Difference to the Base TRR		25-WholesaleDifference, Line 45	$ -
89	Wholesale Base Transmission Revenue Requirement		Line 87 + Line 88	$ -

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 the South Georgia Income Tax Adjustment "Credits and Other" term 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.

Schedule 2
Incremental Forecast Period TRR

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				Reference
	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-BaseTRR, Line 51
13	Wtd. Cost of Common + Pref. Stock:		- %	1-BaseTRR, Line 55
14	Composite Tax Rate:		- %	1-BaseTRR, Line 59
15				
16	AFCRCWIP =		- %	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:	$	-	6-PlantInService, Line 13
28	Distribution Plant - ISO:	$	-	6-PlantInService, Line 16
29	Transmission Dep. Reserve - ISO:	$	-	8-AccDep, Line 13
30	Distribution Dep. Reserve - ISO:	$	-	8-AccDep, Line 16
31	Net Plant:	$	-	(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:	$	-	10-CWIP, L 13 C1
38	AFCRCWIP:		- %	Line 16
39	Direct CWIP Related Costs:	$	-	Line 37 * Line 38
40				
41	**2) CWIP ROE Adder costs:**			
42	IREF:	$	-	15-IncentiveAdder, Line 3
43				
44	Tehachapi CWIP Amount:	$	-	10-CWIP, Line 13
45	Tehachapi ROE Adder %:		- %	15-IncentiveAdder, Line 5
46	Tehachapi ROE Adder $:	$	-	Formula on Line 52
47				
48	DCR CWIP Amount:	$	-	10-CWIP, Line 13
49	DCR ROE Adder %:		- %	15-IncentiveAdder, Line 6
50	DCR ROE Adder $:	$	-	Formula on Line 52
51				
52	ROE Adder $ = (CWIP/$1,000,000) * IREF * (ROE Adder/1%)			
53				
54	CWIP Related Costs wo FF&U:	$	-	Line 39 + Line 46 + Line 50
55	FF&U Expenses:	$	-	(28-FFU, L5 FF Factor + U Factor) * L54
56	CWIP Related Costs with FF&U:	$	-	Line 54 + Line 55
57				

Schedule 2
Incremental Forecast Period TRR

58	**b) Determination of AFCR:**			
59				
60	CWIP Related Costs wo FF&U:	$	-	Line 54
61	Prior Year TRR wo FF&U:	$	-	1-BaseTRR, Line 78
62	Prior Year TRR wo CWIP Related Costs:	$	-	Line 61 - Line 60
63	75% of O&M and A&G in Prior Year TRR:	$	-	(1-BaseTRR, Line 66 + Line 67) * .75
64	AFCR:		- %	(Line 62 - Line 63) / Line 31
65				
66	**2) Calculation of IFP TRR**			
67				
68				**Reference**
69	Forecast Plant Additions:	$	-	16-PlantAdditions, L 25, C10
70	AFCR:		- %	Line 64
71	AFCR * Forecast Plant Additions:	$	-	Line 69 * Line 70
72				
73	Forecast Period Incremental CWIP:	$	-	10-CWIP, L 54, C8
74	AFCRCWIP:		- %	Line 16
75	AFCRCWIP * FP Incremental CWIP:	$	-	Line 73 * Line 74
76				
77	IFPTRR without FF&U:	$	-	Line 71 + Line 75
78				
79	Franchise Fees Expense:	$	-	Line 77 * FF (from 28-FFU, L 5)
80	Uncollectibles Expense:	$	-	Line 77 * U (from 28-FFU, L 5)
81				
82	Incremental Forecast Period TRR:	$	-	Line 77 + Line 79 + Line 80

Schedule 3
True Up Adjustment

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: $ - 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	-	---	---	$ -	$ -	---	$ -	---	$ -
12	January	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
13	February	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
14	March	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
15	April	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
16	May	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
17	June	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
18	July	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
19	August	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
20	September	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
21	October	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
22	November	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -
23	December	-	$ -	$ -	$ -	$ -	- %	$ -	$ -	$ -

24 **3) True Up Adjustment**

Line			Notes:
25			
26	Shortfall or Excess Revenue in Prior Year:	$ -	Line 23, Column 9
27	Previous Annual Update TU Adjustment:	$ -	Previous Annual Update Schedule 3, Line 30
28	TU Adjustment without Projected Interest	$ -	Line 26 - Line 27
29	Projected Interest to Rate Year Mid-Point:	$ -	Line 28 * (Line 23, Column 6) * 18 months
30	True Up Adjustment:	$ -	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).

Previous Annual Update:

32 **4) 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			

54 **Transmission Revenues: (Note 8)**

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7
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								
59–62	**Prior Year Month**	**Actual Retail Base Transmission Revenues**	**Other Transmission**	**Distribution**	**Generation**	**Public Purpose**	**Other**	**Monthly Total Retail Revenue**
63	Jan	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	Feb	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	Mar	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Apr	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	May	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	Jun	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	Jul	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	Aug	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Sep	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Oct	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	Nov	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	Dec	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	Totals:	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76								
77				"Total Sales to Ultimate Consumers" from FERC Form 1 Page 300, Line 10, Column b:				$ -

Schedule 3
True Up Adjustment

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.

Schedule 4
True Up TRR

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	$ -
2	General + Elec. Misc. Intangible Plant	BOY/EOY Avg.		6-PlantInService, Line 24	$ -
3	Transmission Plant Held for Future Use	BOY/EOY Avg.		11-PHFU, Line 9	$ -
4	Abandoned Plant	BOY/EOY Avg.		12-AbandonedPlant Line 4	$ -
	Working Capital Amounts				
5	Materials and Supplies	13-Month Avg.		13-WorkCap, Line 17	$ -
6	Prepayments	13-Month Avg.		13-WorkCap, Line 33	$ -
7	Cash Working Capital	1/8 (O&M + A&G)		1-Base TRR Line 7	$ -
8	Working Capital			Line 5 + Line 6 + Line 7	$ -
	Accumulated Depreciation Reserve Amounts				
9	Transmission Depreciation Reserve - ISO	13-Month Avg.	Negative amount	8-AccDep, Line 14, Col. 12	$ -
10	Distribution Depreciation Reserve - ISO	BOY/EOY Avg.	Negative amount	8-AccDep, Line 17, Col. 5	$ -
11	G + I Depreciation Reserve	BOY/EOY Avg.	Negative amount	8-AccDep, Line 23	$ -
12	Accumulated Depreciation Reserve			Line 9 + Line 10 + Line 11	$ -
13	Accumulated Deferred Income Taxes	Prorata ~~BOY/EOY~~ Avg.		9-ADIT, Line 15	$ -
14	CWIP Plant	13-Month Avg.		14-IncentivePlant, L 12, C2	$ -
15	Network Upgrade Credits	BOY/EOY Avg.	Negative amount	22-NUCs, Line 7	$ -
16	Unfunded Reserves			34-UnfundedReserves, Line 7	$ -
17	Other Regulatory Assets/Liabilities	BOY/EOY Avg.		23-RegAssets, Line 15	$ -
18	Rate Base			L1+L2+L3+L4+L8+L12+ L13+L14+L15+L16+L17	$ -

B) Return on Capital

Line			Notes	Reference	Amount
19	Cost of Capital Rate		See Instruction 1	Instruction 1, Line j	- %
20	Return on Capital: Rate Base times Cost of Capital Rate			Line 18 * Line 19	$ -

C) Income Taxes

Line		Notes	Reference	Amount
21	Income Taxes = [((RB * ER) + D) * (CTR/(1 – CTR))] + CO/(1 – CTR)			$ -
	Where:			
22	RB = Rate Base		Line 18	$ -
23	ER = Equity ROR inc. Com. and Pref. Stock	Instruction 1	Instruction 1, Line k	- %
24	CTR = Composite Tax Rate		1-Base TRR L 59	- %
25	CO = Credits and Other		1-Base TRR L 63	$ -
26	D = Book Depreciation of AFUDC Equity Book Basis		1-Base TRR L 65	$ -

Schedule 4
True Up TRR

D) True Up TRR Calculation

27	O&M Expense	1-Base TRR L 66	$	-
28	A&G Expense	1-Base TRR L 67	$	-
29	Network Upgrade Interest Expense	1-Base TRR L 68	$	-
30	Depreciation Expense	1-Base TRR L 69	$	-
31	Abandoned Plant Amortization Expense	1-Base TRR L 70	$	-
32	Other Taxes	1-Base TRR L 71	$	-
33	Revenue Credits	1-Base TRR L 72	$	-
34	Return on Capital	Line 20	$	-
35	Income Taxes	Line 21	$	-
36	Gains and Losses on Transmission Plant Held for Future Use -- Land	1-Base TRR L 75	$	-
37	Amortization and Regulatory Debits/Credits	1-Base TRR L 76	$	-
38	Total without True Up Incentive Adder	Sum Line 27 to Line 37	$	-
39	True Up Incentive Adder	15-IncentiveAdder L 20	$	-
40	True Up TRR without Franchise Fees and Uncollectibles Expense included:	Line 38 + Line 39	$	-

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

Line				Reference:
41	True Up TRR wo FF:	$	-	Line 40
42	Franchise Fee Factor:		- %	28-FFU, L 5
43	Franchise Fee Expense:	$	-	Line 41 * Line 42
44	Uncollectibles Expense Factor:		- %	28-FFU, L 5
45	Uncollectibles Expense:	$	-	Line 41 * Line 44
46	True Up TRR:	$	-	L 41 + L 43 + L 45

Schedule 4
True Up TRR

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	- %	See Line e below	---	---	---
b	ROE start of Prior Year	- %	See Line f below	---	---	---
c					Total days in year:	
d	Wtd. Avg. ROE in Prior Year	- %	((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	---
f	Beginning of Prior Year	---

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

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

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

Schedule 5 ROR-1
Return and Capitalization

Calculation of Components of Cost of Capital Rate

Cells shaded yellow are input cells

Line		Notes	FERC Form 1 Reference or Instruction	Value
				-
	RETURN AND CAPITALIZATION CALCULATIONS			
	Calculation of Long Term Debt Amount			
1	Bonds -- Account 221	13-month avg.	5-ROR-2, Line 1	$ -
2	Less Reacquired Bonds -- Account 222	13-month avg.	5-ROR-2, Line 2	$ -
3	Long Term Debt Advances from Associated Companies -- Account 223	13-month avg.	5-ROR-2, Line 3	$ -
4	Other Long Term Debt -- Account 224	13-month avg.	5-ROR-2, Line 4	$ -
5 ~~4~~	Unamortized Premium on Long Term Debt - Account 225	13-month avg.	5-ROR-2, Line 5	$ -
6 ~~5~~	Less Unamortized Discount on Long Term Debt -- Account 226	13-month avg.; enter negative	5-ROR-2, Line 6	$ -
7 ~~6~~	Unamortized Debt Expenses -- Account 181	13-month avg.; enter negative	5-ROR-2, Line 7	$ -
8 ~~7~~	Unamortized Loss on Reacquired Debt -- Account 189	13-month avg.; enter negative	5-ROR-2, Line 8	$ -
9 ~~8~~	Composite Tax Rate		1-BaseTRR, Line 59	- %
10 ~~9~~	After tax amount of Unamortized Loss on Reacquired Debt		Line 8 ~~7~~ * (1- Line 9 ~~8~~)	$ -
11 ~~10~~	Removal of Long Term Debt Related to Fuel Inventories	13-month avg.; enter negative	5-ROR-2, Line 9	$ -
12 ~~11~~	Adjustments related to "LT Debt Related to Fuel Inventories"		5-ROR-2, Line 10	$ -
13 ~~12~~	Long Term Debt Amount		Sum of Lines 1 to 7~~6~~ and 10~~9~~ to 12~~11~~	$ -
	Calculation of Preferred Stock Amount			
14 ~~13~~	Preferred Stock Amount -- Account 204	13-month avg.	5-ROR-2, Line 11	$ -
15 ~~14~~	Unamortized Issuance Costs	13-month avg.	5-ROR-2, Line 12	$ -
16 ~~15~~	Net Gain (Loss) From Purchase and Tender Offers	13-month avg.	5-ROR-2, Line 13	$ -
17 ~~16~~	Preferred Stock Amount		Sum of Lines 14 ~~13~~ to 16 ~~15~~	$ -
	Calculation of Common Stock Equity Amount			
18 ~~17~~	Total Proprietary Capital	13-month avg.	5-ROR-2, Lines 14 + 14a	$ -
19 ~~18~~	Less Preferred Stock Amount -- Account 204	Same as L 14 ~~13~~, but negative	5-ROR-2, Line 11	$ -
20 ~~19~~	Minus Net Gain (Loss) From Purchase and Tender Offers	Same as L 16 ~~15~~, but reverse sign	5-ROR-2, Line 13	$ -
21 ~~20~~	Less Unappropriated Undist. Sub. Earnings -- Acct. 216.1	13-month avg.	5-ROR-2, Line 15	$ -
22 ~~21~~	Less Accumulated Other Comprehensive Loss -- Account 219	13-month avg.	5-ROR-2, Line 16	$ -
23 ~~21~~	Common Stock Equity Amount		Sum of Lines 18 ~~17~~ to 22 ~~21~~	$ -

Schedule 5 ROR-2
Return and Capitalization

Calculation of 13-Month Average Capitalization Balances
Year

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		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Reacquired Bonds -- Account 222 (Note 2): enter - of FF1														
2		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Long Term Debt Advances from Associated Companies (Note 3):														
3		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Other Long Term Debt -- Account 224 (Note 4):														
4		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Unamortized Premium on Long Term Debt -- Account 225 (Note 5)														
5		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Less Unamortized Discount on Long Term Debt -- Account 226 (Note 6): enter - of FF1														
6		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Unamortized Debt Expenses -- Account 181 (Note 7): enter - of FF1														
7		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Unamortized Loss on Reacquired Debt -- Account 189 (Note 8): enter - of FF1														
8		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Removal of Long Term Debt Not Financing Rate Base ~~Related to Fuel Inventories~~ (Note 9)														
9		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Adjustments related to "LT Debt Not Financing Rate Base ~~Related to Fuel Inventories~~" (Note 10)														
10		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Preferred Stock Amount -- Account 204 (Note 11):														
11		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Unamortized Issuance Costs (Note 12)~~: enter - of FF1~~														
12		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Net Gain (Loss) From Purchase and Tender Offers (Note 13):														
13		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Total Proprietary Capital (Note 14):														
14		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Proprietary Capital Adjustment for Wildfire Related Capital														
14a		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Unappropriated Undist. Sub. Earnings -- Acct. 216.1 (Note 15): enter - of FF1														
15		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Accumulated Other Comprehensive Loss -- Account 219 (Note 16): enter - of FF1														
16		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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 112.22 d~~c~~, amount in Column 14 from FF1 112.22 c~~d~~, amounts in columns 3-13 from SCE internal records.
6) Amount in Column 2 from FF1 112.23 d~~c~~, amount in Column 14 from FF1 112.23 c~~d~~, amounts in columns 3-13 from SCE internal records.
7) Amount in Column 2 from FF1 111.69 d~~c~~, amount in Column 14 from FF1 111.69 c~~d~~, amounts in columns 3-13 from SCE internal records.
8) Amount in Column 2 from FF1 111.81 d~~c~~, amount in Column 14 from FF1 111.81 c~~d~~, 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 112.16 d~~c~~, amount in Column 14 from FF1 112.16 c~~d~~, amounts in columns 3-13 from SCE internal records.
14a) Represents Capital disclosed by SCE related to Wildfire Related Capital, not yet paid on a cash basis. Amounts in Columns 2-14 are from SCE internal records
15) Amount in Column 2 from FF1 112.12 d~~c~~, amount in Column 14 from FF1 112.12 c~~d~~, amounts in columns 3-13 from SCE internal records.
16) Amount in Column 2 from FF1 112.15 d~~c~~, amount in Column 14 from FF1 112.15 c~~d~~, amounts in columns 3-13 from SCE internal records.

Long Term Debt Cost Percentage

~~At End of Year ("EOY") for~~ Prior Year:

Add yellow shading since this is an input

1) Calculation of "Long Term Debt Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Outstanding Series Debt:	$ -	Line 200, Col 10
2	Total Annual Amortized Loss on Reacquired Debt:	$ -	FF1 117.64c ~~Line 500, Column C~~
3	Total Annual Cost of Debt:	$ -	= L1 + L2
4			
5	Total "Principal Amount Outstanding" Debt:	$ -	Line 200, Col 5
6	Total Reacquired Debt:	$ -	Line 205, Col 5
7	Total Unamortized Loss on Reacquired Debt:	$ -	5-ROR-2, Line 8, Col. 14 (Negative of FF1 111.81c) ~~Line 500, Col 2~~
8	Composite Tax Rate:	- %	1-BaseTRR, Line 59
9	After-Tax Total Unamortized Loss on Reacquired Debt:	$ -	= L7 * (1 - L8)
10 ~~8~~	Total Debt Balance:	$ -	= L5 + L6 + L9~~7~~
11 ~~9~~			
12 ~~10~~	Long Term Debt Cost Percentage:	- %	= L3 / L10~~8~~

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 257~~6~~, Col h~~b~~	Note 1	FF1 256, Col c Note 2 ~~Section 4~~	= Col 5 - Col 7	Note 3 ~~2~~	= Col 5 * Col 9	
Line	**Series**	**Date of Offering**	**Maturity Date**	**Coupon Rate**	**Principal Amount Oustanding ($000s)**	**Amort-ization Period (Years)**	**Net Discount & Issuance Cost ($000s)**	**Net Proceeds ($000s)**	**Cost of Money**	**Annual Cost ($000s)**	**Comments: See below**
101						---	$ -	$ -	- %	$ -	
102						---	$ -	$ -	- %	$ -	
103						---	$ -	$ -	- %	$ -	
104						---	$	$ -	- %	$ -	
105						---	$	-	- %	$ -	
106						---	$	-	- %	$ -	
107						---	$ -	$ -	- %	$ -	
108						---	$ -	$ -	- %	$ -	
109						---	$ -	$ -	- %	$ -	
110						---	$ -	$ -	- %	$ -	
111						---	$ -	$ -	- %	$ -	
112						---	$ -	$ -	- %	$ -	
113						---	$ -	$ -	- %	$ -	
114						---	$ -	$ -	- %	$ -	
115						---	$ -	$ -	- %	$ -	
116						---	$ -	$ -	- %	$ -	
117						---	$ -	$ -	- %	$ -	
118						---	$ -	$ -	- %	$ -	
119						---	$ -	$ -	- %	$ -	
120						---	$ -	$ -	- %	$ -	
121						---	$ -	$ -	- %	$ -	
122						---	$ -	$ -	- %	$ -	
123						---	$ -	$ -	- %	$ -	
124						---	$ -	$ -	- %	$ -	
125						---	$ -	$ -	- %	$ -	
126						---	$ -	$ -	- %	$ -	
127						---	$ -	$ -	- %	$ -	
128						---	$ -	$ -	- %	$ -	
129						---	$ -	$ -	- %	$ -	
130						---	$ -	$ -	- %	$ -	
131						---	$ -	$ -	- %	$ -	
132						---	$ -	$ -	- %	$ -	
133	…										

Add yellow shading since this column is input now

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

Comment #:	Comment
…	

200 **Total Principal Amount Outstanding (sum of above * 1,000):** $ - **Total Annual Cost (sum of above * 1,000):** $ -

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						
202						
203						
204	…					
205				**Total Principal Amount (sum of above * 1,000):**	$ -	

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~~

	~~Col 1~~	~~Col 2~~	~~Col 3~~
~~Line~~	~~Series~~	~~Unamortized Debt Issuance Cost (Dec of Prior Year)~~	~~Total Unamortized Debt Discounts (Dec of PY)~~
~~301~~			
~~302~~			
~~303~~			
~~304~~			
~~305~~			
~~306~~			
~~307~~			
~~308~~			
~~309~~			
~~310~~			
~~311~~			
~~312~~			
~~313~~			
~~314~~			
~~315~~			
~~316~~			
~~317~~			
~~318~~			
~~319~~			
~~320~~			
~~321~~			
~~322~~			
~~323~~			
~~324~~			
~~325~~			
~~326~~			
~~327~~			
~~328~~			
~~329~~			
~~330~~			
~~331~~			
~~332~~			
~~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~~			
~~402~~			
~~403~~			
~~404~~			
~~405~~			
~~406~~			
~~407~~			
~~408~~			
~~409~~			
~~410~~			
~~411~~			
~~412~~			
~~413~~			
~~414~~			
~~415~~			
~~416~~			
~~417~~			
~~418~~			
~~419~~			
~~420~~			
~~421~~			
~~422~~			
~~423~~			
~~424~~			
~~425~~			
~~426~~			
~~427~~			
~~428~~			
~~429~~			
~~430~~			
~~431~~			
~~432~~			
~~433~~			
~~434~~			
~~435~~			
~~436~~			
~~437~~			
~~438~~			
~~439~~			

~~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~~			
~~441~~			
~~442~~			
~~443~~			
~~444~~			
~~445~~			
~~446~~			
~~447~~			
~~448~~			
~~449~~			
~~450~~			
~~451~~			
~~452~~			
~~500~~	~~Totals (sum of above * 1000):~~	~~$ -~~	~~$ -~~

Notes:

1) Equal to maturity date less the date of offering ~~end of the year for prior~~ year

2) Sum of all amounts for each issuance

3 ~~2~~) 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money

4) Excludes debt, or portions thereof, that does not finance Rate Base

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

Add yellow shading since this is an input now

1) Calculation of "Preferred Stock Cost Percentage"

Line		Amount	Reference
1	Total Annual Cost of Preferred Stock:	$ -	Line 112, Col 9
2	Total Reacquired Preferred Stock Cost:	$ -	Line 312, Col 6
3	Total Annual Cost of Preferred:	$ -	= L1 + L2
4			
5	Total Preferred Stock Amount Outstanding:	$ -	FF1 112.3c ~~Line 112, Col 4~~
	Net Gain (Loss) from Purchase and Tender Offers:	$ -	Line 312, Col 4
6	~~Total Unamortized Issuance Costs:~~		
7	Total Preferred Balance:	$ -	= L5 - L6
8			
9	Preferred Stock Cost Percentage:	- %	= L3 / L7

2) Preferred Stock Information for each Outstanding Series

Line	Col 1 FF1 250, Col a Preferred Stock	Col 2 SCE Records Issue Date	Col 3 FF1 250, Col a Dividend Rate	Col 4 FF1 251, Col f Face Value / Amount Ou~~s~~t~~s~~tanding ($'000s)	Col 5 Sec 3, Col 2 Total Issuance Cost ($'000s)	Col 6 = Col 4 - Col 5 Net Proceeds at Issuance ($'000s)	Col 7 = Col 6 / Col 4 % of Face Value	Col 8 = Col 3 / Col 7 Note 1 Cost of Money / Effective Rate	Col 9 = Col 4 * Col 8 Annualized Cost ($'000s)	Notes
101					$ -	$ -	- %	- %	$ -	
102					$ -	$ -	- %	- %	$ -	
103					$ -	$ -	- %	- %	$ -	
104					$ -	$ -	- %	- %	$ -	
105					$ -	$ -	- %	- %	$ -	
106					$ -	$ -	- %	- %	$ -	
107					$ -	$ -	- %	- %	$ -	
108					$ -	$ -	- %	- %	$ -	
109					$ -	$ -	- %	- %	$ -	
110					$ -	$ -	- %	- %	$ -	
111	…				$ -	$ -	- %	- %	$ -	
112	~~Total Amount Outstanding (sum of above * 1,000):~~			~~$ -~~				Total Annual Cost (sum of above * 1,000):	$ -	

3) Preferred Stock Issuance Cost Details for each Outstanding Series

Line	Col 1 Same list as in Section 2 Preferred Stock	Col 2 SCE Records Total Issuance Cost ($'000s)	~~Col 3~~ ~~SCE Records~~ ~~Unamortized Issuance Cost ('000s)~~	Col ~~3~~4 SCE Records Full Amortization Period	Col ~~4~~5 Notes
201					
202					
203					
204					
205					
206					
207					
208					
209					
210					
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 ($000s)	Col 4 SCE Records Net Gain (Loss) from Purchase and Tender Offers ~~Unamortized Issuance Cost~~ ($'000s)	Col 5 SCE Records Amortization Period	Col 6 Col 3 / Col 5 ~~SCE Records~~ Issuance Amortization Cost ($'000s)	Notes
301						$ -	
302						$ -	
303						$ -	
304						$ -	
305						$ -	
306						$ -	
307						$ -	
308						$ -	
309						$ -	
310						$ -	
311	…					$ -	
312	Total Annual Cost (sum of above * 1,000):			$ -		$ -	

Notes:
1) If issuance costs not fully amortized then the "Cost of Money Effective Rate" is the 18 CFR 35.13 (22) Statement AV - Rate of Return (ii)(B)(6) Cost of money.
If the issuance costs are fully amortized then the "Cost of Money Effective Rate" is equal to Column 3 / Column 7.

Schedule 6
Plant In Service

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: -

	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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	13-Mo. Avg:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
16	-	$ -	$ -	$ -	$ -
17	Average:	$ -	$ -	$ -	$ -

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

		Amount	Source
18	Average value:	$ -	Sum of Line 14, Col 12 and Line 17, Col 5
19	EOY Value:	$ -	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

	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	$ -	$ -	$ -	BOY amount from previous PY
21	December	FF1 207.99.g and 205.5g	$ -	$ -	$ -	End of year ("EOY") amount

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

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

Transmission Activity Used to Determine Monthly Transmission Plant - ISO Balances

1) Total Transmission Plant Balances by Account (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
	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 6
Plant In Service

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
82	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
94	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
95	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
96	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
97	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
98	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
99	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
100	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
101	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
102	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
103	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
104	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %

7) 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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

	350.1	350.2	352	353	354	355	356	357	358	359	Total
106	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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

	350.1	350.2	352	353	354	355	356	357	358	359	Total
107	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 6
Plant In Service

8) 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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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.

Schedule 7
Transmission Plant Study Summary

Transmission Plant Study — Input cells are shaded yellow

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

Line	Account	Col 1 Total Plant	Data Source	Col 2 Transmission Plant - ISO	Col 3 ISO % of Total	Notes
1						
2	**Substation**					
3	352	$ -	FF1 207.49g	$ -	- %	
4	353	$ -	FF1 207.50g	$ -	- %	
5	**Total Substation**	$ -	L 3 + L 4	$ -	- %	
6						
7	**Land**					
8	350	$ -	FF1 207.48g	$ -	- %	
9						
10	**Total Substation and Land**	$ -	L 5 + L 8	$ -	- %	
11						
12	**Lines**					
13	354	$ -	FF1 207.51g	$ -	- %	
14	355	$ -	FF1 207.52g	$ -	- %	
15	356	$ -	FF1 207.53g	$ -	- %	
16	357	$ -	FF1 207.54g	$ -	- %	
17	358	$ -	FF1 207.55g	$ -	- %	
18	359	$ -	FF1 207.56~~0~~g	$ -	- %	
19	**Total Lines**	$ -	Sum L13 to L18	$ -	- %	
20						
21	**Total Transmission**	$ -	L 10 + L 19	$ -	- %	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	$ -	FF1 207.60g	$ -	- %	
25	**Structures:**					
26	361	$ -	FF1 207.61g	$ -	- %	
27	362	$ -	FF1 207.62g	$ -	- %	
28	**Total Structures**	$ -	L 26 + L 27	$ -	- %	
29						
30	**Total Distribution**	$ -	L 24 + L 28	$ -	- %	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".

Schedule 8
Accumulated Depreciation

Accumulated Depreciation Reserve

Input cells are shaded yellow

1) Transmission Depreciation Reserve - ISO

Prior Year: -

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
		FERC Account:										=Sum C2 to C11
Line	Mo/YR	350.1	350.2	352	353	354	355	356	357	358	359	Total
1	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	13-Mo. Avg:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$0	Beginning of Year ("BOY") amount
16	-	$ -	$ -	$ -	$0	End of Year ("EOY") amount
17	BOY/EOY Average:	$ -	$ -	$ -	$0	Average of Line 15 and Line 16

Schedule 8
Accumulated Depreciation

3) General and Intangible Depreciation Reserve

	Col 1	Col 2	Col 3	Col 4	Col 5	
			=C4+C5			
			Total Gen. and Int. Depreciation Reserve	General Depreciation Reserve	Intangible Depreciation Reserve	
	Mo/YR					Source
18	-	BOY:	$ -	$ -	$ -	FF1 219.28c and 200.21c for previous year
19	-	EOY:	$ -	$ -	$ -	FF1 219.28c and 200.21c
20		BOY/EOY Average:	$ -			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:	$ -	Line 20
22	Transmission W&S Allocation Factor:	- %	27-Allocators, Line 9
23	G + I Plant Dep. Reserve (BOY/EOY Average):	$ -	Line 21 * Line 22

b) EOY General and Intangible Depreciation Reserve

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

Schedule 8
Accumulated Depreciation

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
41	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
42	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
43	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
44	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
45	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
46	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
47	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
48	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
49	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
50	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%
51	-	-%	-%	-%	-%	-%	-%	-%	-%	-%	-%

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

B) Total Depreciation Expense (See Note 6)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
53	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

C) Other Activity (See Note 7)

	350.1	350.2	352	353	354	355	356	357	358	359	Total
54	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Schedule 8
Accumulated Depreciation

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Total:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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 and Net Excess Deferred Tax Liabilities

Cells shaded yellow are input cells

1) Summary of Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

a) End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities

Line	Col 1 Account	Col 2 Total Balance ~~ADIT~~	Source
1	Account 190	$ -	Line 353, Col. 2
2	Account 282	$ -	Line 452, Col. 2
3	Account 283	$ -	Line 803, Col. 2
4	Net Excess/Deficient Deferred Tax Liability/Asset-2017 TCAJA	$ -	FF1 278, see Notes 4 and 5
5	Total Accumulated Deferred Income Taxes	$ -	Sum of Lines 1 to 4
6	and Net Excess Deferred Tax Liabilities		
7	**b) Beginning of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
8		**BOY**	
9		**Balance ~~ADIT~~**	**Source**
10	Total Accumulated Deferred Income Taxes	$ -	Previous Year Informational Filing, Line 5, Col. 2
11			
12	**c) Prorata Average of Beginning and End of Year Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities**		
13		**Average**	
14		**ADIT**	**Source**
15	Prorata Average Balance ~~ADIT~~:	$ -	Line 817, Column 8

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	-	-	$ -	$ -	$ -	$ -	$ -	-
101	-	-	$ -	$ -	$ -	$ -	$ -	-
102	-	-	$ -	$ -	$ -	$ -	$ -	-
103	-	-	$ -	$ -	$ -	$ -	$ -	-
104	-	-	$ -	$ -	$ -	$ -	$ -	-
105	-	-	$ -	$ -	$ -	$ -	$ -	-
106	-	-	$ -	$ -	$ -	$ -	$ -	-
107	-	-	$ -	$ -	$ -	$ -	$ -	-
108	-	-	$ -	$ -	$ -	$ -	$ -	-
109	-	-	$ -	$ -	$ -	$ -	$ -	-
110	-	-	$ -	$ -	$ -	$ -	$ -	-
111	-	-	$ -	$ -	$ -	$ -	$ -	-
112	-	-	$ -	$ -	$ -	$ -	$ -	-
113	-	-	$ -	$ -	$ -	$ -	$ -	-
114	-	-	$ -	$ -	$ -	$ -	$ -	-
115	-	-	$ -	$ -	$ -	$ -	$ -	-
116	-	-	$ -	$ -	$ -	$ -	$ -	-
117	-	-	$ -	$ -	$ -	$ -	$ -	-
118	-	-	$ -	$ -	$ -	$ -	$ -	-
119	-	-	$ -	$ -	$ -	$ -	$ -	-
120	-	-	$ -	$ -	$ -	$ -	$ -	-
121	-	-	$ -	$ -	$ -	$ -	$ -	-
122	-	-	$ -	$ -	$ -	$ -	$ -	-
123	-	-	$ -	$ -	$ -	$ -	$ -	-
124	-	-	$ -	$ -	$ -	$ -	$ -	-
125	-	-	$ -	$ -	$ -	$ -	$ -	-
126	-	-	$ -	$ -	$ -	$ -	$ -	-
127	-	-	$ -	$ -	$ -	$ -	$ -	-
128	-	-	$ -	$ -	$ -	$ -	$ -	-
129	-	-	$ -	$ -	$ -	$ -	$ -	-
130	-	-	$ -	$ -	$ -	$ -	$ -	-
131	-	-	$ -	$ -	$ -	$ -	$ -	-
132	-	-	$ -	$ -	$ -	$ -	$ -	-
133	-	-	$ -	$ -	$ -	$ -	$ -	-
134	-	-	$ -	$ -	$ -	$ -	$ -	-
135	-	-	$ -	$ -	$ -	$ -	$ -	-
136	-	-	$ -	$ -	$ -	$ -	$ -	-
137	-	-	$ -	$ -	$ -	$ -	$ -	-
138	-	-	$ -	$ -	$ -	$ -	$ -	-
139	-	-	$ -	$ -	$ -	$ -	$ -	-
140	-	-	$ -	$ -	$ -	$ -	$ -	-
141	-	-	$ -	$ -	$ -	$ -	$ -	-

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:							
142	-	-	$ -	$ -	$ -	$ -	$ -	-
143	-	-	$ -	$ -	$ -	$ -	$ -	-
144	-	-	$ -	$ -	$ -	$ -	$ -	-
145	-	-	$ -	$ -	$ -	$ -	$ -	-
146	-	-	$ -	$ -	$ -	$ -	$ -	-
147	-	-	$ -	$ -	$ -	$ -	$ -	-
148	-	-	$ -	$ -	$ -	$ -	$ -	-
149	-	-	$ -	$ -	$ -	$ -	$ -	-
150	-	-	$ -	$ -	$ -	$ -	$ -	-
151	-	-	$ -	$ -	$ -	$ -	$ -	-
152	-	-	$ -	$ -	$ -	$ -	$ -	-
153	-	-	$ -	$ -	$ -	$ -	$ -	-
154	-	-	$ -	$ -	$ -	$ -	$ -	-
155	-	-	$ -	$ -	$ -	$ -	$ -	-
156	-	-	$ -	$ -	$ -	$ -	$ -	-
157	-	-	$ -	$ -	$ -	$ -	$ -	-
158	-	-	$ -	$ -	$ -	$ -	$ -	-
159	-	-	$ -	$ -	$ -	$ -	$ -	-
160	-	-	$ -	$ -	$ -	$ -	$ -	-
161	-	-	$ -	$ -	$ -	$ -	$ -	-
162	-	-	$ -	$ -	$ -	$ -	$ -	-
163	-	-	$ -	$ -	$ -	$ -	$ -	-
164	-	-	$ -	$ -	$ -	$ -	$ -	-
165	-	-	$ -	$ -	$ -	$ -	$ -	-
166	-	-	$ -	$ -	$ -	$ -	$ -	-
167	-	-	$ -	$ -	$ -	$ -	$ -	-
168	-	-	$ -	$ -	$ -	$ -	$ -	-
169	-	-	$ -	$ -	$ -	$ -	$ -	-
170	-	-	$ -	$ -	$ -	$ -	$ -	-
171	-	-	$ -	$ -	$ -	$ -	$ -	-
172	-	-	$ -	$ -	$ -	$ -	$ -	-
173	-	-	$ -	$ -	$ -	$ -	$ -	-
174	-	-	$ -	$ -	$ -	$ -	$ -	-
175	…							
								Source
250		Total Electric 190	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 100

	Account 190 Gas and Other Income:	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	(Instructions 1&2) Col 7
300	-	-	$ -	$ -	$ -	$ -	$ -	-
301	-	-	$ -	$ -	$ -	$ -	$ -	-
302	-	-	$ -	$ -	$ -	$ -	$ -	-
303	-	-	$ -	$ -	$ -	$ -	$ -	-
304	-	-	$ -	$ -	$ -	$ -	$ -	-
305	-	-	$ -	$ -	$ -	$ -	$ -	-
306	-	-	$ -	$ -	$ -	$ -	$ -	-
307	-	-	$ -	$ -	$ -	$ -	$ -	-
308	-	-	$ -	$ -	$ -	$ -	$ -	-
309	-	-	$ -	$ -	$ -	$ -	$ -	-
310	-	-	$ -	$ -	$ -	$ -	$ -	-
311	-	-	$ -	$ -	$ -	$ -	$ -	-
312	-	-	$ -	$ -	$ -	$ -	$ -	-
313	-	-	$ -	$ -	$ -	$ -	$ -	-
314	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
350	Total Account 190 Gas and Other Income	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 300
351	Total Account 190	$ -	$ -	$ -	$ -	$ -	Line 250 + Line 350
352	Allocation Factors (Plant and Wages)				- %	- %	27-Allocators Lines 22 and 9 respectively.
353	Total Account 190 ADIT (Sum of amounts in Columns 4 to 6)	$ -		$ -	$ -	$ -	Line 351 * Line 352 for Cols 5 and 6. Col. 4 100% ISO.
354	FERC Form 1 Account 190	$ -	Must match amount on Line 351, Col. 2				FF1 234.18c

3) Account 282 Detail

	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	-	-	$ -	$ -	$ -	$ -	$ -	-
401	-	-	$ -	$ -	$ -	$ -	$ -	-
402	-	-	$ -	$ -	$ -	$ -	$ -	-
403	-	-	$ -	$ -	$ -	$ -	$ -	-
404	-	-	$ -	$ -	$ -	$ -	$ -	-
405	-	-	$ -	$ -	$ -	$ -	$ -	-
406	-	-	$ -	$ -	$ -	$ -	$ -	-
407	-	-	$ -	$ -	$ -	$ -	$ -	-
408	-	-	$ -	$ -	$ -	$ -	$ -	-
409	-	-	$ -	$ -	$ -	$ -	$ -	-
410	-	-	$ -	$ -	$ -	$ -	$ -	-
411	-	-	$ -	$ -	$ -	$ -	$ -	-
412	-	-	$ -	$ -	$ -	$ -	$ -	-
413	-	-	$ -	$ -	$ -	$ -	$ -	-
414	-	-	$ -	$ -	$ -	$ -	$ -	-
415	-	-	$ -	$ -	$ -	$ -	$ -	-
416	-	-	$ -	$ -	$ -	$ -	$ -	-
417	-	-	$ -	$ -	$ -	$ -	$ -	-
418	-	-	$ -	$ -	$ -	$ -	$ -	-
419	-	-	$ -	$ -	$ -	$ -	$ -	-
420	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
450	Total Account 282	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 400
451	Allocation Factors (Plant and Wages)				- %	- %	27-Allocators Lines 22 and 9 respectively.
452	Total Account 282 ADIT (Sum of amounts in Columns 4 to 6)	$ -		$ -	$ -	$ -	Line 450 * Line 451 for Cols 5 and 6. Col. 4 100% ISO.
453	FERC Form 1 Account 282	$ -	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	-	-	$ -	$ -	$ -	$ -	$ -	-
501	-	-	$ -	$ -	$ -	$ -	$ -	-
502	-	-	$ -	$ -	$ -	$ -	$ -	-
503	-	-	$ -	$ -	$ -	$ -	$ -	-
504	-	-	$ -	$ -	$ -	$ -	$ -	-
505	-	-	$ -	$ -	$ -	$ -	$ -	-
506	-	-	$ -	$ -	$ -	$ -	$ -	-
507	-	-	$ -	$ -	$ -	$ -	$ -	-
508	-	-	$ -	$ -	$ -	$ -	$ -	-
509	-	-	$ -	$ -	$ -	$ -	$ -	-
510	-	-	$ -	$ -	$ -	$ -	$ -	-
511	-	-	$ -	$ -	$ -	$ -	$ -	-
512	-	-	$ -	$ -	$ -	$ -	$ -	-
513	-	-	$ -	$ -	$ -	$ -	$ -	-
514	-	-	$ -	$ -	$ -	$ -	$ -	-
515	-	-	$ -	$ -	$ -	$ -	$ -	-
516	-	-	$ -	$ -	$ -	$ -	$ -	-
517	-	-	$ -	$ -	$ -	$ -	$ -	-
518	-	-	$ -	$ -	$ -	$ -	$ -	-
519	-	-	$ -	$ -	$ -	$ -	$ -	-
520	-	-	$ -	$ -	$ -	$ -	$ -	-
521	-	-	$ -	$ -	$ -	$ -	$ -	-
522	-	-	$ -	$ -	$ -	$ -	$ -	-
523	-	-	$ -	$ -	$ -	$ -	$ -	-
524	-	-	$ -	$ -	$ -	$ -	$ -	-
525	-	-	$ -	$ -	$ -	$ -	$ -	-
526	-	-	$ -	$ -	$ -	$ -	$ -	-
527	-	-	$ -	$ -	$ -	$ -	$ -	-
528	-	-	$ -	$ -	$ -	$ -	$ -	-
529	-	-	$ -	$ -	$ -	$ -	$ -	-
530	-	-	$ -	$ -	$ -	$ -	$ -	-
531	-	-	$ -	$ -	$ -	$ -	$ -	-
532	-	-	$ -	$ -	$ -	$ -	$ -	-
533	-	-	$ -	$ -	$ -	$ -	$ -	-
534	-	-	$ -	$ -	$ -	$ -	$ -	-
535	-	-	$ -	$ -	$ -	$ -	$ -	-
536	-	-	$ -	$ -	$ -	$ -	$ -	-
537	-	-	$ -	$ -	$ -	$ -	$ -	-
538	-	-	$ -	$ -	$ -	$ -	$ -	-
539	-	-	$ -	$ -	$ -	$ -	$ -	-

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):							
540	-	-	$ -	$ -	$ -	$ -	$ -	-
541	-	-	$ -	$ -	$ -	$ -	$ -	-
542	-	-	$ -	$ -	$ -	$ -	$ -	-
543	-	-	$ -	$ -	$ -	$ -	$ -	-
544	-	-	$ -	$ -	$ -	$ -	$ -	-
545	-	-	$ -	$ -	$ -	$ -	$ -	-
546	-	-	$ -	$ -	$ -	$ -	$ -	-
547	-	-	$ -	$ -	$ -	$ -	$ -	-
548	-	-	$ -	$ -	$ -	$ -	$ -	-
549	-	-	$ -	$ -	$ -	$ -	$ -	-
550	-	-	$ -	$ -	$ -	$ -	$ -	-
551	-	-	$ -	$ -	$ -	$ -	$ -	-
552	-	-	$ -	$ -	$ -	$ -	$ -	-
553	-	-	$ -	$ -	$ -	$ -	$ -	-
554	-	-	$ -	$ -	$ -	$ -	$ -	-
555	-	-	$ -	$ -	$ -	$ -	$ -	-
556	-	-	$ -	$ -	$ -	$ -	$ -	-
557	-	-	$ -	$ -	$ -	$ -	$ -	-
558	-	-	$ -	$ -	$ -	$ -	$ -	-
559	-	-	$ -	$ -	$ -	$ -	$ -	-
560	-	-	$ -	$ -	$ -	$ -	$ -	-
561	-	-	$ -	$ -	$ -	$ -	$ -	-
562	-	-	$ -	$ -	$ -	$ -	$ -	-
563	-	-	$ -	$ -	$ -	$ -	$ -	-
564	-	-	$ -	$ -	$ -	$ -	$ -	-
565	-	-	$ -	$ -	$ -	$ -	$ -	-
566	-	-	$ -	$ -	$ -	$ -	$ -	-
567	-	-	$ -	$ -	$ -	$ -	$ -	-
568	-	-	$ -	$ -	$ -	$ -	$ -	-
569	…							
650	Total Electric 283		$0	$0	$0	$0	$0	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	-	-	$ -	$ -	$ -	$ -	$ -	-
701	-	-	$ -	$ -	$ -	$ -	$ -	-
702	-	-	$ -	$ -	$ -	$ -	$ -	-
703	-	-	$ -	$ -	$ -	$ -	$ -	-
704	-	-	$ -	$ -	$ -	$ -	$ -	-
705	-	-	$ -	$ -	$ -	$ -	$ -	-
706	-	-	$ -	$ -	$ -	$ -	$ -	-
707	-	-	$ -	$ -	$ -	$ -	$ -	-
708	-	-	$ -	$ -	$ -	$ -	$ -	-
709	-	-	$ -	$ -	$ -	$ -	$ -	-
710	-	-	$ -	$ -	$ -	$ -	$ -	-
711	-	-	$ -	$ -	$ -	$ -	$ -	-
712	-	-	$ -	$ -	$ -	$ -	$ -	-
713	…							

	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Source
800	Total Account 283 Gas and Other	$ -	$ -	$ -	$ -	$ -	Sum of Above Lines beginning on Line 700
801	Total Account 283	$ -	$ -	$ -	$ -	$ -	Line 650 + Line 800
802	Allocation Factors (Plant and Wages)				- %	- %	27-Allocators Lines 22 and 9 respectively.
803	Total Account 283 ADIT (Sum of amounts in Columns 4 to 6)	$ -		$ -	$ -	$ -	Line 801 * Line 802 for Cols 5 and 6. Col. 4 100% ISO.
804	FERC Form 1 Account 283	$ -	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)

	Col 1 Future Test Period	Col 2 See Note 1 Mthly Deferred Tax Amount	Col 3 See Note 2 Deferred Tax Balance	Col 4 Days in Month	Col 5 Number of Days Left in Period	Col 6 Col 5 / Tot. Days Prorata Percentages	Col 7 = Col 2 * Col 6 Monthly Prorata Amounts	Col 8 See Note 3 Annual Accumulated Prorata Calculation
805	Beginning Deferred Tax Balance (Line 10, Col. 2)		$ -		-	- %		$ -
806	January	$ -	$ -	-	-	- %	$ -	$ -
807	February	$ -	$ -	-	-	- %	$ -	$ -
808	March	$ -	$ -	-	-	- %	$ -	$ -
809	April	$ -	$ -	-	-	- %	$ -	$ -
810	May	$ -	$ -	-	-	- %	$ -	$ -
811	June	$ -	$ -	-	-	- %	$ -	$ -
812	July	$ -	$ -	-	-	- %	$ -	$ -
813	August	$ -	$ -	-	-	- %	$ -	$ -
814	September	$ -	$ -	-	-	- %	$ -	$ -
815	October	$ -	$ -	-	-	- %	$ -	$ -
816	November	$ -	$ -	-	-	- %	$ -	$ -
817	December	$ -	$ -	-	-	- %	$ -	$ -
818	Ending Balance (Line 5, Col. 2)		$ -					

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	$ -
B:Gas Wages and Salaries	FF1 355.62b	$ -
C:Water Wages and Salaries	FF1 355.64b	$ -
D:Total Electric, Gas, and Water Wages and Salaries	A+B+C	$ -
E:Labor Percentage "Gas, Generation, or Other"	(B+C) / D	- %

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	$ -
G:Total Gas Plant In Service	FF1 201.8d	$ -
H:Total Water Plant in Service	FF1 201.8e	$ -
I:Total Electric, Gas, and Water Plant In Service	F+G+H	$ -
J:Plant Percentage "Gas, Generation, or Other"	(G+H) / I	- %

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 Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities ~~ADIT~~ balance minus the beginning Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities ~~ADIT~~ balance, divided by 12 months.
2) For January through December = previous month balance plus amount in Column 2.
3) The average Accumulated Deferred Income Taxes and Net Excess Deferred Tax Liabilities ~~ADIT~~ Balance is equal to the amount on Line 817, Column 8. Line 805 is equal to Line 10, Column 2. Lines 806 through 817 equal previous amount in Column 8, plus amount in Column 7.
4) The net excess/deficiency is derived from the deficiency arising in Account 190 offset by excesses in Accounts 282 and 283.
5) SCE must submit a Federal Power Act Section 205 filing to obtain Commission approval prior to reflecting in rates any regulatory assets and liabilities arising from future tax changes.

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

Line	Month	Year	Col 1 = Sum of all columns Monthly Total CWIP	Col 2 Tehachapi	Col 3 Devers to Colorado River	Col 4 South of Kramer	Col 5 West of Devers	Col 6 Red Bluff
1	December	-	$ -	$ -	$ -	$ -	$ -	$ -
2	January	-	$ -	$ -	$ -	$ -	$ -	$ -
3	February	-	$ -	$ -	$ -	$ -	$ -	$ -
4	March	-	$ -	$ -	$ -	$ -	$ -	$ -
5	April	-	$ -	$ -	$ -	$ -	$ -	$ -
6	May	-	$ -	$ -	$ -	$ -	$ -	$ -
7	June	-	$ -	$ -	$ -	$ -	$ -	$ -
8	July	-	$ -	$ -	$ -	$ -	$ -	$ -
9	August	-	$ -	$ -	$ -	$ -	$ -	$ -
10	September	-	$ -	$ -	$ -	$ -	$ -	$ -
11	October	-	$ -	$ -	$ -	$ -	$ -	$ -
12	November	-	$ -	$ -	$ -	$ -	$ -	$ -
13	December	-	$ -	$ -	$ -	$ -	$ -	$ -
14	13 Month Averages:		$ -	$ -	$ -	$ -	$ -	$ -

Line	Month	Year	Col 7 Whirlwind Substation Expansion	Col 8 Colorado River Substation Expansion	Col 9	Col 10	Col 11	Col 12
15	December	-	$ -	$ -	$ -	$ -	---	---
16	January	-	$ -	$ -	$ -	$ -	---	---
17	February	-	$ -	$ -	$ -	$ -	---	---
18	March	-	$ -	$ -	$ -	$ -	---	---
19	April	-	$ -	$ -	$ -	$ -	---	---
20	May	-	$ -	$ -	$ -	$ -	---	---
21	June	-	$ -	$ -	$ -	$ -	---	---
22	July	-	$ -	$ -	$ -	$ -	---	---
23	August	-	$ -	$ -	$ -	$ -	---	---
24	September	-	$ -	$ -	$ -	$ -	---	---
25	October	-	$ -	$ -	$ -	$ -	---	---
26	November	-	$ -	$ -	$ -	$ -	---	---
27	December	-	$ -	$ -	$ -	$ -	---	---
28	13 Month Averages:		$ -	$ -	$ -	$ -	$ -	$ -

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

			Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8
			See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2	See Note 2
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**
29	December	-	---	---	---	---	---	---	$ -	---
30	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
37	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
42	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
43	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
46	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	**13-Month Averages:**									**$ -**

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

3a) Project: Tehachapi

			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**
55	December	-	---	---	---	---	---	---	$ -	---
56	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
74	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
75	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
78	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
79	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
80	**13-Month Averages:**									**$ -**

Schedule 10
CWIP

3b) Project: Devers to Colorado River

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
			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
81	December	-	---	---	---	---	---	---	$0	---
82	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
83	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
84	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
87	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
88	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
89	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
92	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
93	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
94	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
97	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
98	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
99	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
100	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
101	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
102	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
103	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
104	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
105	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
106	13-Month Averages:									$ -

3c) Project: South of Kramer

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
			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	-	---	---	---	---	---	---	$0	---
108	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
109	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
110	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
112	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
113	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
116	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
117	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
120	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
121	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
125	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
127	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
128	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
129	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
131	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
132	13-Month Averages:									$ -

3d) Project: West of Devers

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	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
133	December	-	---	---	---	---	---	---	$0	---
134	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
135	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
136	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
139	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
140	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
141	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
142	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
143	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
144	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
145	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
146	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
147	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
148	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
150	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
151	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
152	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
153	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
154	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
155	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
156	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
157	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
158	13-Month Averages:									$ -

3e) Project: Red Bluff

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	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Forecast Period CWIP	Forecast Period Incremental CWIP
159	December	-	---	---	---	---	---	---	$0	---
160	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
161	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
162	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
163	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
164	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
165	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
166	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
167	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
168	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
170	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
171	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
172	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
173	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
174	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
175	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
176	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
177	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
178	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
179	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
180	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
181	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
182	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
183	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
184	13-Month Averages:									$ -

Schedule 10
CWIP

3f) Project: Whirlwind Substation Expansion

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 Unload 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
185	December	-	---	---	---	---	---	---	$0	---
186	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
187	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
188	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
189	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
190	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
191	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
192	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
193	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
194	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
195	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
196	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
197	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
198	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
199	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
200	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
201	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
202	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
203	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
204	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
205	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
206	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
207	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
208	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
209	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
210	13-Month Averages:									$ -

3g) Project: Colorado River Substation Expansion

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
211	December	-	---	---	---	---	---	---	$0	---
212	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
213	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
214	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
215	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
216	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
217	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
218	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
219	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
220	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
221	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
222	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
223	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
224	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
225	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
226	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
227	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
228	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
229	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
230	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
231	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
232	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
233	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
234	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
235	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
236	13-Month Averages:									$ -

3h) Project:

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
237	December	-	---	---	---	---	---	---	$0	---
238	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
239	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
240	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
241	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
242	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
243	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
244	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
245	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
246	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
247	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
248	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
249	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
250	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
251	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
252	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
253	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
254	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
255	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
256	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
257	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
258	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
259	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
260	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
261	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
262	13-Month Averages:									$ -

3i) Project:

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
263	December	-	---	---	---	---	---	---	$0	---
264	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
265	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
266	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
267	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
268	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
269	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
270	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
271	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
272	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
273	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
274	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
275	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
276	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
277	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
278	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
279	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
280	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
281	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
282	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
283	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
284	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
285	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
286	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
287	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
288	13-Month Averages:									$ -

Schedule 10
CWIP

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

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
289	December	-	---	---	---	---	---	---	$0	---
290	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
291	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
292	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
293	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
294	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
295	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
296	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
297	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
298	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
299	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
300	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
301	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
302	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
303	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
304	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
305	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
306	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
307	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
308	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
309	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
310	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
311	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
312	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
313	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
314	13-Month Averages:									$ -

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.

Schedule 11
Plant Held for Future Use

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	$ -	$ -	FF1 page 214.47d

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

	Col 1	Col 2	Col 3	Col 4	Col 5
	Description	Type of Plant	Beginning of Year Balance	End of Year Balance	Source
2a			$ -	$ -	
2b			$ -	$ -	
2c			$ -	$ -	
2d			$ -	$ -	
2e			$ -	$ -	
2f			$ -	$ -	
2g			$ -	$ -	
2h			$ -	$ -	
	...				
3		Total:	$ -	$ -	Sum of above lines

		Beginning of Year Balance	End of Year Balance	Source
4	General Plant Held for Future Use	$ -	$ -	FF1 page 214
5	Wages and Salaries AF:	- %	- %	27-Allocators, L 9
6	Portion for Transmission PHFU:	$ -	$ -	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		$ -	$ -	Note 1

	Transmission PHFU:	Beginning of Year Balance	End of Year Balance	Source
8		$ -	$ -	L 3 + L 6
9	Average of BOY and EOY Transmission PHFU:	$ -		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	$ -	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.

Schedule 12
Abandoned Plant

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:	---	---
	---	---
	…	…

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:	$ -	Sum of projects below for PY.
2	Abandoned Plant (BOY):	$ -	Sum of projects below for PY.
3	Abandoned Plant (EOY):	$ -	Sum of projects below for PY.
4	Abandoned Plant (BOY/EOY Average):	$ -	Average of Lines 2 and 3.
5	HV Abandoned Plant (BOY):	$ -	Sum of projects below for PY.

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

Line	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	$ -	$ -	$ -	$ -	$ -	$ -
8	2016	$ -	$ -	$ -	$ -	$ -	$ -
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.

Schedule 13
Working Capital

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	-	FF1 227.12b	$ -	Beginning of year ("BOY") amount
2	January	-	SCE Records	$ -	
3	February	-	SCE Records	$ -	
4	March	-	SCE Records	$ -	
5	April	-	SCE Records	$ -	
6	May	-	SCE Records	$ -	
7	June	-	SCE Records	$ -	
8	July	-	SCE Records	$ -	
9	August	-	SCE Records	$ -	
10	September	-	SCE Records	$ -	
11	October	-	SCE Records	$ -	
12	November	-	SCE Records	$ -	
13	December	-	FF1 227.12c	$ -	End of Year ("EOY") amount
14	13-Month Average Value Account 154:			$ -	(Sum Line 1 to Line 13) / 13
15	Transmission Wages and Salaries AF:			- %	27-Allocators, Line 9
16	**Materials and Supplies** EOY Value:			$ -	Line 13 * Line 15
17	13-Month Average Value:			$ -	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	-	Note 1, c	$ -	See Note 1, c
19	January	-	SCE Records	$ -	
20	February	-	SCE Records	$ -	
21	March	-	SCE Records	$ -	
22	April	-	SCE Records	$ -	
23	May	-	SCE Records	$ -	
24	June	-	SCE Records	$ -	
25	July	-	SCE Records	$ -	
26	August	-	SCE Records	$ -	
27	September	-	SCE Records	$ -	
28	October	-	SCE Records	$ -	
29	November	-	SCE Records	$ -	
30	December	-	Note 1, f	$ -	See Note 1, f

a) 13-Month Average Calculation

31	13-Month Average Value:	$ -	(Sum Line 18 to Line 30) / 13
32	Transmission Wages and Salaries AF:	- %	27-Allocators, Line 9
33	Prepayments:	$ -	Line 31 * Line 32

b) EOY calculation

34	EOY Value:	$ -	Line 30
35	Transmission Wages and Salaries AF:	- %	27-Allocators, Line 9
36	Prepayments:	$ -	Line 34 * Line 35

Notes:

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

Beginning of Year Amount

	Item	Prepayments Balances	Source
a	FERC Form 1 Acct. 165 Recorded Amount:	$ -	FF1 111.57d
b	Prior Period Adjustment:	$ -	Note 1
c	BOY Prepayments Amount:	$ -	a - b

End of Year Amount

	Item	Prepayments Balances	Source
d	FERC Form 1 Acct. 165 Recorded Amount:	$ -	FF1 111.57c
e	Prior Period Adjustment:	$ -	Note 1
f	EOY Prepayments Amount:	$ -	d - e

Schedule 14
Incentive Plant

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	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 80
2	2) Devers-Colorado River	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 106
3	3) South of Kramer	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 132
4	4) West of Devers	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 158
5	5) Red Bluff	$ -	$ -	$ -	10-CWIP Lines 13, 14, and 184
6	6) Whirlwind Substation Exp.	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 210
7	7) Colorado River Sub. Exp.	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 236
8	8)	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 262
9	9)	$ -	$ -	$ -	10-CWIP Lines 27, 28, and 288
10	…				…
11					
12	Totals:	$ -	$ -	$ -	

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	$ -	$ -	$ -	Line 37, C4
14	2) Tehachapi	$ -	$ -	$ -	Line 1, C1, and Line 37, C2
15	3) Devers-Colorado River	$ -	$ -	$ -	Line 2, C1, and Line 37, C3
16	…				…
17					
18	Total PY Incentive Net Plant:	$ -			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	$ -	$ -	$ -	Line 38, C4
20	2) Tehachapi	$ -	$ -	$ -	Line 1, C2, and Line 38, C2
21	3) Devers-Colorado R	$ -	$ -	$ -	Line 2, C2, and Line 38, C3
22	…				…
23					
24	Total PY Incentive Net Plant:	$ -			13 Month Average

Schedule 14
Incentive Plant

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	-	$ -	$ -	$ -	$ -	---	←December of year previous to Prior Year
26	January	-	$ -	$ -	$ -	$ -	---	
27	February	-	$ -	$ -	$ -	$ -	---	
28	March	-	$ -	$ -	$ -	$ -	---	
29	April	-	$ -	$ -	$ -	$ -	---	
30	May	-	$ -	$ -	$ -	$ -	---	
31	June	-	$ -	$ -	$ -	$ -	---	
32	July	-	$ -	$ -	$ -	$ -	---	
33	August	-	$ -	$ -	$ -	$ -	---	
34	September	-	$ -	$ -	$ -	$ -	---	
35	October	-	$ -	$ -	$ -	$ -	---	
36	November	-	$ -	$ -	$ -	$ -	---	
37	December	-	$ -	$ -	$ -	$ -	---	
38		13 Month Averages:	$ -	$ -	$ -	$ -		

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	-	$ -	$ -	$ -	C1: Sum of below projects for each month
40	January	-	$ -	$ -	$ -	
41	February	-	$ -	$ -	$ -	
42	March	-	$ -	$ -	$ -	
43	April	-	$ -	$ -	$ -	
44	May	-	$ -	$ -	$ -	
45	June	-	$ -	$ -	$ -	
46	July	-	$ -	$ -	$ -	
47	August	-	$ -	$ -	$ -	
48	September	-	$ -	$ -	$ -	
49	October	-	$ -	$ -	$ -	
50	November	-	$ -	$ -	$ -	
51	December	-	$ -	$ -	$ -	
52	Total		$ -	$ -	$ -	

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	-	$ -	$ -	$ -	$ -
54	January	-	$ -	$ -	$ -	$ -
55	February	-	$ -	$ -	$ -	$ -
56	March	-	$ -	$ -	$ -	$ -
57	April	-	$ -	$ -	$ -	$ -
58	May	-	$ -	$ -	$ -	$ -
59	June	-	$ -	$ -	$ -	$ -
60	July	-	$ -	$ -	$ -	$ -
61	August	-	$ -	$ -	$ -	$ -
62	September	-	$ -	$ -	$ -	$ -
63	October	-	$ -	$ -	$ -	$ -
64	November	-	$ -	$ -	$ -	$ -
65	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

	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	-	$ -	$ -	$ -	$ -
67	January	-	$ -	$ -	$ -	$ -
68	February	-	$ -	$ -	$ -	$ -
69	March	-	$ -	$ -	$ -	$ -
70	April	-	$ -	$ -	$ -	$ -
71	May	-	$ -	$ -	$ -	$ -
72	June	-	$ -	$ -	$ -	$ -
73	July	-	$ -	$ -	$ -	$ -
74	August	-	$ -	$ -	$ -	$ -
75	September	-	$ -	$ -	$ -	$ -
76	October	-	$ -	$ -	$ -	$ -
77	November	-	$ -	$ -	$ -	$ -
78	December	-	$ -	$ -	$ -	$ -

	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	-	$ -	$ -	$ -	$ -
80	January	-	$ -	$ -	$ -	$ -
81	February	-	$ -	$ -	$ -	$ -
82	March	-	$ -	$ -	$ -	$ -
83	April	-	$ -	$ -	$ -	$ -
84	May	-	$ -	$ -	$ -	$ -
85	June	-	$ -	$ -	$ -	$ -
86	July	-	$ -	$ -	$ -	$ -
87	August	-	$ -	$ -	$ -	$ -
88	September	-	$ -	$ -	$ -	$ -
89	October	-	$ -	$ -	$ -	$ -
90	November	-	$ -	$ -	$ -	$ -
91	December	-	$ -	$ -	$ -	$ -

	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	-	$ -	$ -	$ -	$ -
93	January	-	$ -	$ -	$ -	$ -
94	February	-	$ -	$ -	$ -	$ -
95	March	-	$ -	$ -	$ -	$ -
96	April	-	$ -	$ -	$ -	$ -
97	May	-	$ -	$ -	$ -	$ -
98	June	-	$ -	$ -	$ -	$ -
99	July	-	$ -	$ -	$ -	$ -
100	August	-	$ -	$ -	$ -	$ -
101	September	-	$ -	$ -	$ -	$ -
102	October	-	$ -	$ -	$ -	$ -
103	November	-	$ -	$ -	$ -	$ -
104	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

e) West of Devers

	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
105	December	-	$ -	$ -	$ -	$ -
106	January	-	$ -	$ -	$ -	$ -
107	February	-	$ -	$ -	$ -	$ -
108	March	-	$ -	$ -	$ -	$ -
109	April	-	$ -	$ -	$ -	$ -
110	May	-	$ -	$ -	$ -	$ -
111	June	-	$ -	$ -	$ -	$ -
112	July	-	$ -	$ -	$ -	$ -
113	August	-	$ -	$ -	$ -	$ -
114	September	-	$ -	$ -	$ -	$ -
115	October	-	$ -	$ -	$ -	$ -
116	November	-	$ -	$ -	$ -	$ -
117	December	-	$ -	$ -	$ -	$ -

f) Red Bluff

	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
118	December	-	$ -	$ -	$ -	$ -
119	January	-	$ -	$ -	$ -	$ -
120	February	-	$ -	$ -	$ -	$ -
121	March	-	$ -	$ -	$ -	$ -
122	April	-	$ -	$ -	$ -	$ -
123	May	-	$ -	$ -	$ -	$ -
124	June	-	$ -	$ -	$ -	$ -
125	July	-	$ -	$ -	$ -	$ -
126	August	-	$ -	$ -	$ -	$ -
127	September	-	$ -	$ -	$ -	$ -
128	October	-	$ -	$ -	$ -	$ -
129	November	-	$ -	$ -	$ -	$ -
130	December	-	$ -	$ -	$ -	$ -

g) Whirlwind 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
131	December	-	$ -	$ -	$ -	$ -
132	January	-	$ -	$ -	$ -	$ -
133	February	-	$ -	$ -	$ -	$ -
134	March	-	$ -	$ -	$ -	$ -
135	April	-	$ -	$ -	$ -	$ -
136	May	-	$ -	$ -	$ -	$ -
137	June	-	$ -	$ -	$ -	$ -
138	July	-	$ -	$ -	$ -	$ -
139	August	-	$ -	$ -	$ -	$ -
140	September	-	$ -	$ -	$ -	$ -
141	October	-	$ -	$ -	$ -	$ -
142	November	-	$ -	$ -	$ -	$ -
143	December	-	$ -	$ -	$ -	$ -

Schedule 14
Incentive Plant

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	-	$ -	$ -	$ -	$ -
145	January	-	$ -	$ -	$ -	$ -
146	February	-	$ -	$ -	$ -	$ -
147	March	-	$ -	$ -	$ -	$ -
148	April	-	$ -	$ -	$ -	$ -
149	May	-	$ -	$ -	$ -	$ -
150	June	-	$ -	$ -	$ -	$ -
151	July	-	$ -	$ -	$ -	$ -
152	August	-	$ -	$ -	$ -	$ -
153	September	-	$ -	$ -	$ -	$ -
154	October	-	$ -	$ -	$ -	$ -
155	November	-	$ -	$ -	$ -	$ -
156	December	-	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
158	January	-	$ -	$ -	$ -	$ -
159	February	-	$ -	$ -	$ -	$ -
160	March	-	$ -	$ -	$ -	$ -
161	April	-	$ -	$ -	$ -	$ -
162	May	-	$ -	$ -	$ -	$ -
163	June	-	$ -	$ -	$ -	$ -
164	July	-	$ -	$ -	$ -	$ -
165	August	-	$ -	$ -	$ -	$ -
166	September	-	$ -	$ -	$ -	$ -
167	October	-	$ -	$ -	$ -	$ -
168	November	-	$ -	$ -	$ -	$ -
169	December	-	$ -	$ -	$ -	$ -

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	-	$ -	$ -	$ -	$ -
171	January	-	$ -	$ -	$ -	$ -
172	February	-	$ -	$ -	$ -	$ -
173	March	-	$ -	$ -	$ -	$ -
174	April	-	$ -	$ -	$ -	$ -
175	May	-	$ -	$ -	$ -	$ -
176	June	-	$ -	$ -	$ -	$ -
177	July	-	$ -	$ -	$ -	$ -
178	August	-	$ -	$ -	$ -	$ -
179	September	-	$ -	$ -	$ -	$ -
180	October	-	$ -	$ -	$ -	$ -
181	November	-	$ -	$ -	$ -	$ -
182	December	-	$ -	$ -	$ -	$ -

6) Summary of Incentive Projects and incentives granted

	A) Rancho Vista Incentives Received:		**Cite:**
183	CWIP:	-	-
184	ROE adder:	- %	-
185	100% Abandoned Plant:	-	-
	B) Tehachapi Incentives Received:		**Cite:**
186	CWIP:	-	-
187	ROE adder:	- %	-
188	100% Abandoned Plant:	-	-
	C) Devers to Colorado River Incentives Received:		**Cite:**
189	CWIP:	-	-
190	ROE adder:	- %	-
191			
192	100% Abandoned Plant:	-	-
	D) Devers to Palo Verde 2 Incentives Received:		**Cite:**
193	CWIP:	-	-
194			
195	ROE adder:	- %	-
196			
197	100% Abandoned Plant:	-	-
	E) South of Kramer Incentives Received:		**Cite:**
198	CWIP:	-	-
199	ROE adder:	- %	-
200	100% Abandoned Plant:	-	-
	F) West of Devers Incentives Received:		**Cite:**
201	CWIP:	-	-
202	ROE adder:	- %	-
203	100% Abandoned Plant:	-	-
	G) Red Bluff Incentives Received:		**Cite:**
204	CWIP:	-	-
205	ROE adder:	- %	-
206	100% Abandoned Plant:	-	-
	H) Whirlwind Substation Expansion Incentives Received:		**Cite:**
207	CWIP:	-	-
208	ROE adder:	- %	-
209	100% Abandoned Plant:	-	-
	I) Colorado River Substation Expansion Incentives Received:		**Cite:**
210	CWIP:	-	-
211	ROE adder:	- %	-
212	100% Abandoned Plant:	-	-
	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.

Schedule 15
Incentive Adders

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		- %	1-BaseTRR, L 47
2	CTR = Composite Tax Rate		- %	1-BaseTRR, L 59
3		IREF =	$ -	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	- %	--	14-IncentivePlant, L 184
5	2) Tehachapi	- %	--	14-IncentivePlant, L 187
6	3) Devers to Col. River	- %	--	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	$ -	--	$ -	14-IncentivePlant, L 13, Col. 1
10	2) Tehachapi	$ -	--	$ -	14-IncentivePlant, L 14, Col. 1
11	3) Devers to Col. River	$ -	--	$ -	14-IncentivePlant, L 15, Col. 1
12					
13	…				
14			Prior Year Incentive Adder =	$ -	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	$ -	--	$ -	14-IncentivePlant, L 19, Col. 1
16	2) Tehachapi	$ -	--	$ -	14-IncentivePlant, L 20, Col. 1
17	3) Devers to Col. River	$ -	--	$ -	14-IncentivePlant, L 21, Col. 1
18					
19	…				
20			True-Up Incentive Adder =	$ -	Sum of above PY Incentive Adders for each individual project

Schedule 15
Incentive Adders

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	$ -	14-IncentivePlant, L 19, Col. 3
22	2) Tehachapi	$ -	14-IncentivePlant, L 20, Col. 3
23	3) Devers to Col. River	$ -	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	$ -	$ -	See Note 1
26	2) Tehachapi	$ -	$ -	See Note 1
27	3) Devers to Col. River	$ -	$ -	See Note 1
28				See Note 1
29	…			
30		Total:	$ -	

c) Equity Portion of Plant In Service Rate Base

Line		Amount	Source
31	Total Rate Base:	$ -	4-TUTRR, Line 18
32	CWIP Portion of Rate Base:	$ -	4-TUTRR, Line 14
33	Plant In Service Rate Base:	$ -	Line 31 - Line 32
34	Equity percentage:	- %	1-BaseTRR, Line 47
35	Equity Portion of Plant In Service Rate Base:	$ -	Line 33 * Line 34

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

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

Schedule 16
Plant Additions

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
19	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
22	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	13-Month Averages:								$ -			$ -		$ -

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	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
27	February	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
28	March	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
29	April	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
30	May	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
31	June	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
32	July	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
33	August	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
34	September	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
35	October	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
36	November	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
37	December	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
38	January	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
39	February	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
40	March	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
41	April	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
42	May	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
43	June	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
44	July	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
45	August	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
46	September	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
47	October	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
48	November	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -
49	December	-	$ -	$ -	$ -	$0	$0	$0	$ -	$ -	$ -	$ -	$ -	$ -

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

Line	Forecast Period Month	Year	Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11	Col 12
					=(C1-C2)*L74	=(C1-C2+C3)*L75	=C1-C2+C3-C4	=C5*L76	= Prior Month C2 +C2+C5+C6	= Prior Month C7 * L91/12	= Prior Month C9 + C4 + C8	=C7-C9		=C11* (1-L75) * (1+L74+L76)
Line	Forecast Period Month	Year	Unloaded Total Plant Adds	Prior Period CWIP Closed	Over Heads Closed to PIS	Cost of Removal	AFUDC Eligible Plant Additions	AFUDC	Incremental Gross Plant	Depreciation Accrual	Incremental Reserve	Net Plant	Unloaded Low Voltage Additions	Loaded Low Voltage Additions
50	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
51	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
52	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
53	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
54	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
55	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
56	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
58	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
59	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	January	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
63	February	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
64	March	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
65	April	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	May	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	June	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
68	July	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
69	August	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
70	September	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	October	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	November	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
73	December	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

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	$ -	- %	$ -	18 Dep Rates L1
78	350.2	$ -	- %	$ -	18 Dep Rates L2
79	352	$ -	- %	$ -	18 Dep Rates L3
80	353	$ -	- %	$ -	18 Dep Rates L4
81	354	$ -	- %	$ -	18 Dep Rates L5
82	355	$ -	- %	$ -	18 Dep Rates L6
83	356	$ -	- %	$ -	18 Dep Rates L7
84	357	$ -	- %	$ -	18 Dep Rates L8
85	358	$ -	- %	$ -	18 Dep Rates L9
86	359	$ -	- %	$ -	18 Dep Rates L10
87					
88	Sum of Depreciation Expense			$ -	Sum of C4 Lines 77 to 86
89	Sum of Dec Prior Year Plant			$ -	Sum of C2 Lines 77 to 86
90					
91	Composite Depreciation Rate			- %	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

Schedule 17
Depreciation Expense

Depreciation Expense Input cells are shaded yellow

1) Calculation of Depreciation Expense for Transmission Plant - ISO Prior Year: -

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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
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	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17b	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17c	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17d	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17e	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17f	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17g	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17h	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17i	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17j	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17k	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17l	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
17m	-	- %	- %	- %	- %	- %	- %	- %	- %	- %	- %
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	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
27	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
29	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
31	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
32	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
33	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	-	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
36	Totals:	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
37										Total Annual Depreciation Expense for Transmission Plant - ISO:		$ -
38										(equals sum of monthly amounts)		

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

Line		Amount	Source
56	**3) Calculation of Depreciation Expense for General Plant and Intangible Plant**		
57			
58	Total General Plant Depreciation Expense	$ -	FF1 336.10f
59	Total Intangible Plant Depreciation Expense	$ -	FF1 336.1f
60	Sum of Total General and Total Intangible Depreciation Expense	$ -	Line 58 + Line 59
61	Transmission Wages and Salaries Allocation Factor	- %	27-Allocators, Line 9
62	General and Intangible Depreciation Expense	$ -	Line 60 * Line 61
63			
64	**4) Depreciation Expense**		
65			
66	Depreciation Expense is the sum of:	**Amount**	**Source**
67	1) Depreciation Expense for Transmission Plant - ISO	$ -	Line 37, Col 12
68	2) Depreciation Expense for Distribution Plant - ISO	$ -	Line 53
69	3) General and Intangible Depreciation Expense	$ -	Line 62
70	Depreciation Expense:	$ -	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 are input based on the stated values of ISO Transmission Plant depreciation rates from Schedule 18 of the Formula Rate Spreadsheet in effect during the Prior Year.

~~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.

Schedule 18
Depreciation Rates

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%

Notes: 1) Depreciation rates may only be revised as approved by the Commission pursuant to a Section 205 or 206 filing.

Schedule 19
Operations and Maintenance

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	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**
Line	**Transmission Accounts**										
1	560 - Operations Supervision and Engineering - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
2	560 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
3	561 Load Dispatch - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
4	561.400 Scheduling, System Control and Dispatch Services	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
5	561.500 Reliability Planning and Standards Development	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
6	562 - Station Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
7	562 - MOGS Station Expense	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
8	562 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
9	563 - Overhead Line Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
10	564 - Underground Line Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
11	565 - Transmission of Electricity by Others	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
12	565 - Wheeling Costs	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
13	565 - WAPA Transmission for Remote Service	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
14	566 - Miscellaneous Transmission Expenses - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
15	566 - ISO/RSBA/TSP Balancing Accounts	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
16	566 - Sylmar/Palo Verde/Other General Functions	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
17	567 - Line Rents - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
18	567 - Eldorado	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
19	567 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
20	568 - Maintenance Supervision and Engineering - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
21	568 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
22	569 - Maintenance of Structures - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
23	569 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
24	570 - Maintenance of Station Equipment - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
25	570 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
26	571 - Maintenance of Overhead Lines - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
27	571 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
28	572 - Maintenance of Underground Lines - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
29	572 - Sylmar/Palo Verde	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
30	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
31	...	---	---	---	---	---	---	---			
32	Transmission NOIC (Note 3)	-	-	-		$ -	$ -	$ -	$ -	$ -	$ -
33	**Total Transmission O&M**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34											

Schedule 19
Operations and Maintenance

	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	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
36	590 - Maintenance Supervision and Engineering	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
37	591 - Maintenance of Structures	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
38	592 - Maintenance of Station Equipment	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
39	Accounts with no ISO Distribution Costs	$ -	$ -	$ -	-	$ -	$ -	$ -	$ -	$ -	$ -
40	Distribution NOIC (Note 3)	-	-	-		$ -	$ -	$ -	$ -	$ -	$ -
41	**Total Distribution O&M**	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
42											
43	**Total Transmission and Distribution O&M**	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
44											
45	Total Transmission O&M Expenses in FERC Form 1:	$ -	FF1 321.112b	Must equal Line 33, Column 2.							
46	Total Distribution O&M Expenses in FERC Form 1:	$ -	FF1 322.156b	Must equal Line 41, Column 2.							
47	Total TDBU NOIC	$ -	20-AandG, Note 2, f								

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

Line	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	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
49	560 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
50	561 Load Dispatch - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
51	561.400 Scheduling, System Control and Dispatch Services	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
52	561.500 Reliability Planning and Standards Development	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
53	562 - Station Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
54	562 - MOGS Station Expense	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
55	562 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
56	563 - Overhead Line Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
57	564 - Underground Line Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 36
58	565 - Transmission of Electricity by Others	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
59	565 - Wheeling Costs	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
60	565 - WAPA Transmission for Remote Service	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
61	566 - Miscellaneous Transmission Expenses - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
62	566 - ISO/RSBA/TSP Balancing Accounts	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
63	566 - Sylmar/Palo Verde/Other General Functions	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
64	567 - Line Rents - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
65	567 - Eldorado	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
66	567 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
67	568 - Maintenance Supervision and Engineering - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
68	568 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
69	569 - Maintenance of Structures - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
70	569 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
71	570 - Maintenance of Station Equipment - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
72	570 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
73	571 - Maintenance of Overhead Lines - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 30
74	571 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
75	572 - Maintenance of Underground Lines - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 36
76	572 - Sylmar/Palo Verde	$ -	$ -	$ -	100%	$ -	$ -	$ -	100%
77	573 - Maintenance of Miscellaneous Trans. Plant - Allocated	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 42
78	…	---	---	---	---	---	---	---	
79	Transmission NOIC (Note 4)	-	-	-		$ -	$ -	-	
80	**Total Transmission - ISO O&M**	$ -	$ -	$ -		$ -	$ -	$ -	
81									

Schedule 19
Operations and Maintenance

	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	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
83	590 - Maintenance Supervision and Engineering	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
84	591 - Maintenance of Structures	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
85	592 - Maintenance of Station Equipment	$ -	$ -	$ -	- %	$ -	$ -	$ -	27-Allocators Line 48
86	Accounts with no ISO Distribution Costs	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
87	Distribution NOIC (Note 4)	$ -	$ -	$ -	0%	$ -	$ -	$ -	0%
88	**Total Distribution - ISO O&M**	$ -	$ -	$ -		$ -	$ -	$ -	
89									
90									
91	**Total ISO O&M Expenses (in Column 6)**	$ -	$ -	$ -		$ -	$ -	$ -	
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: ---

	Percentage	Calculation
Transmission NOIC Percentage:	- %	Line 33, Col 3 / Line 43, Col 3
Distribution NOIC Percentage:	- %	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: - %

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.

Schedule 20
Administrative and General Expenses

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	$ -	FF1 323.181b	$ -	$ -	
2	921	Office Supplies and Expenses	$ -	FF1 323.182b	$ -	$ -	
3	922	A&G Expenses Transferred	$ -	FF1 323.183b	$ -	$ -	Credit
4	923	Outside Services Employed	$ -	FF1 323.184b	$ -	$ -	
5	924	Property Insurance	$ -	FF1 323.185b	$ -	$ -	
6	925	Injuries and Damages	$ -	FF1 323.186b	$ -	$ -	
7	926	Employee Pensions and Benefits	$ -	FF1 323.187b	$ -	$ -	
8	927	Franchise Requirements	$ -	FF1 323.188b	$ -	$ -	
9	928	Regulatory Commission Expenses	$ -	FF1 323.189b	$ -	$ -	
10	929	Duplicate Charges	$ -	FF1 323.190b	$ -	$ -	
11	930.1	General Advertising Expense	$ -	FF1 323.191b	$ -	$ -	
12	930.2	Miscellaneous General Expense	$ -	FF1 323.192b	$ -	$ -	
13	931	Rents	$ -	FF1 323.193b	$ -	$ -	
14	935	Maintenance of General Plant	$ -	FF1 323.196b	$ -	$ -	
15			$ -		Total A&G Expenses:	$ -	

Line		Amount	Source
16	Remaining A&G after exclusions & NOIC Adjustment:	$ -	Line 15
17	Less Account 924:	$ -	Line 5
18	Amount to apply the Transmission W&S AF:	$ -	Line 16 - Line 17
19	Transmission Wages and Salaries Allocation Factor:	- %	27-Allocators, Line 9
20	Transmission W&S AF Portion of A&G:	$ -	Line 18 * Line 19
21	Transmission Plant Allocation Factor:	- %	27-Allocators, Line 22
22	Property Insurance portion of A&G:	$ -	Line 5 Col 4 * Line 21
23	Administrative and General Expenses:	$ -	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	$ -	$ -	$ -	$ -	$ -	See Instructions 2b, 3, and Note 2
25	921	$ -	$ -	$ -	$ -	$ -	
26	922	$ -	$ -	$ -	$ -	$ -	
27	923	$ -	$ -	$ -	$ -	$ -	
28	924	$ -	$ -	$ -	$ -	$ -	
29	925	$ -	$ -	$ -	$ -	$ -	
30	926	$ -	$ -	$ -	$ -	$ -	See Note 3
31	927	$ -	$ -	$ -	$ -	$ -	See Note 4
32	928	$ -	$ -	$ -	$ -	$ -	
33	929	$ -	$ -	$ -	$ -	$ -	
34	930.1	$ -	$ -	$ -	$ -	$ -	
35	930.2	$ -	$ -	$ -	$ -	$ -	
36	931	$ -	$ -	$ -	$ -	$ -	
37	935	$ -	$ -	$ -	$ -	$ -	

Schedule 20
Administrative and General Expenses

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:	$ -	SCE Records
b	Actual A&G NOIC payout:	$ -	Note 2, d
c	Adjustment:	$ -	

Actual non-capitalized NOIC Payouts:

	Department		Amount	Source
d	A&G		$ -	SCE Records and Workpapers
e	Other		$ -	SCE Records and Workpapers
f	Trans. And Dist. Business Unit		$ -	SCE Records and Workpapers
g		Total:	$ -	Sum of d to f

Note 3: PBOPs Exclusion Calculation

		Amount	Note:
a	Current Authorized PBOPs Expense Amount:	$18,219,000	See instruction #4
b	Prior Year Authorized PBOPs Expense Amount	$ -	Authorized PBOPs Expense Amount during Prior Year
c	Prior Year FF1 PBOPs expense:	$ -	SCE Records
d	PBOPs Expense Exclusion:	$ -	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: ----
5) SCE shall make no adjustments to recorded labor amounts related to non-labor labor and/or Indirect labor in Schedule 20.

Schedule 21
Revenue Credits

	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.	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
1b	450	4191115	Residential Late Payment	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
2	450 Total			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
3	FF-1 Total for Acct 450 - Forfeited Discounts, p300.16b (Must Equal Line 2)			$ -										
4a	451	4182110	Recover Unauthorized Use/Non-Energy	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4b	451	4182115	Miscellaneous Service Revenue - Ownership Cost	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4c	451	4192110	Miscellaneous Service Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4d	451	4192115	Returned Check Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4e	451	4192125	Service Reconnection Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4f	451	4192130	Service Establishment Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4g	451	4192140	Field Collection Charges	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4h	451	4192510	Quickcheck Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
4i	451	4192910	PUC Reimbursement Fee-Elect	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
4j	451	4182120	Uneconomic Line Extension	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4k	451	4192152	Opt Out CARE-Res-Ini	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4l	451	4192155	Opt Out CARE-Res-Mo	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4m	451	4192158	Opt Out NonCARE-Res-Ini	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4n	451	4192160	Opt Out NonCARE-Res-Mo	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4o	451	4192135	Conn-Charge - Residential	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4p	451	4192145	Conn-Charge - Non-Residential	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
4q	451	4192150	Conn-Charge - At Pole	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
5	451 Total			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
6	FF-1 Total for Acct 451 - Misc. Service Revenues, p300.17b (Must Equal Line 5)			$ -										
8	453 Total			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
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	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10b	454	4184112	Joint Pole - Tariffed Pole Rental - Cable Cos.	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10c	454	4184114	Joint Pole - Tariffed Process & Eng Fees - Cable	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10d	454	4184120	Joint Pole - Aud - Unauth Penalty	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10e	454	4184510	Joint Pole - Non-Tariffed Pole Rental	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10f	454	4184512	Joint Pole - Non-Tariff Process & Engineering Fees	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10g	454	4184514	Joint Pole - Non-Tariff Requests for Information	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10h	454	4184516	Oil And Gas Royalties	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10i	454	4184518	Def Operating Land & Facilities Rent Rev	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10j	454	4184810	Facility Cost -EIX/Nonutility	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
10k	454	4184815	Facility Cost- Utility	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
10l	454	4184820	Rent Billed to Non-Utility Affiliates	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
10m	454	4184825	Rent Billed to Utility Affiliates	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
10n	454	4194110	Meter Leasing Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
10o	454	4194115	Company Financed Added Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10p	454	4194120	Company Financed Interconnect Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10q	454	4194130	SCE Financed Added Faclty	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10r	454	4194135	Interconnect Facility Finance Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	8
10s	454	4204515	Operating Land & Facilities Rent Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10t	454	4867020	Nonoperating Misc Land & Facilities Rent	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10u	454	-	Miscellaneous Adjustments	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
10v	454	4206515	Op Misc Land/Fac Rev	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
10w	454	4184122	T-Unauth Pole Rent	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
10x	454	4184124	T-P&E Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
11	454 Total			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
12	FF-1 Total for Acct 454 - Rent from Elec. Property, p300.19b (Must Equal Line 11)			$ -										

Schedule 21
Revenue Credits

	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	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12b	456	4186118	Distribution Miscellaneous Electric Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12c	456	4186120	Added Facilities - One Time Charge	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12d	456	4186122	Building Rental - Nev Power/Mohave Cr	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	3
12e	456	4186126	Service Fee - Optimal Bill Prd	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12f	456	4186128	Miscellaneous Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12g	456	4186130	Tule Power Plant - Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	3
12h	456	4186142	Microwave Agreement	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12i	456	4186150	Utility Subs Labor Markup	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7
12j	456	4186155	Non Utility Subs Labor Markup	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6, 12
12k	456	4186162	Reliant Eng FSA Ann Pymnt-Mandalay	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12l	456	4186164	Reliant Eng FSA Ann Pymnt-Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12m	456	4186166	Reliant Eng FSA Ann Pymnt-Etiwanda	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12n	456	4186168	Reliant Eng FSA Ann Pymnt-Ellwood	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12o	456	4186170	Reliant Eng FSA Ann Pymnt-Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12p	456	4186194	Property License Fee revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12q	456	4186512	Revenue From Recreation, Fish & Wildlife	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12r	456	4186514	Mapping Services	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12s	456	4186518	Enhanced Pump Test Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12t	456	4186524	Revenue From Scrap Paper - General Office	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12u	456	4186528	CTAC Revenues	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12v	456	4186530	AGTAC Revenues	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
12w	456	4186716	ADT Vendor Service Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12x	456	4186718	Read Water Meters - Irvine Ranch	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12y	456	4186720	Read Water Meters - Rancho California	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12z	456	4186722	Read Water Meters - Long Beach	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12aa	456	4186730	SSID Transformer Repair Services Revenue	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12bb	456	4186815	Employee Transfer/Affiliate Fee	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12cc	456	4186910	ITCC/CIAC Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12dd	456	4186912	Revenue From Decommission Trust Fund	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ee	456	4186914	Revenue From Decommissioning Trust FAS115	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ff	456	4186916	Offset to Revenue from NDT Earnings/Realized	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12gg	456	4186918	Offset to Revenue from FAS 115 FMV	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12hh	456	4186920	Revenue From Decommissioning Trust FAS115-1	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12ii	456	4186922	Offset to Revenue from FAS 115-1 Gains & Loss	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12jj	456	4188712	Power Supply Installations - IMS	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12kk	456	4188714	Consulting Fees - IMS	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
12ll	456	4196105	DA Revenue	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12mm	456	4196158	EDBL Customer Finance Added Facilities	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12nn	456	4196162	SCE Energy Manager Fee Based Services	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12oo	456	4196166	SCE Energy Manager Fee Based Services Adj	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12pp	456	4196172	Off Grid Photo Voltaic Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12qq	456	4196174	Scheduling/Dispatch Revenues	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12rr	456	4196176	Interconnect Facilities Charges-Customer Financed	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	8
12ss	456	4196178	Interconnect Facilities Charges - SCE Financed	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12tt	456	4196184	DMS Service Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
12uu	456	4196188	CCA - Information Fees	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12vv	456	-	Miscellaneous Adjustments	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	1
12ww	456	4186911	Grant Amortization	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
12xx	456	4186925	GHG Allowance Revenue	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
13	**456 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
14	**FF-1 Total for Acct 456 - Other electric Revenues, p300.21b (Must Equal Line 13)**			$ -										

Schedule 21
Revenue Credits

	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	$ -	$ -	$ -	$ -		$ -	$ -	$ -	5
15b	456.1	4188114	FTS PPU/Non-ISO	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15c	456.1	4188116	FTS Non-PPU/Non-ISO	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15d	456.1	4188812	ISO-Wheeling Revenue - Low Voltage	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15e	456.1	4188814	ISO-Wheeling Revenue - High Voltage	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15f	456.1	4188816	ISO-Congestion Revenue	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
15g	456.1	4198110	Transmission of Elec of Others	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	5
15h	456.1	4198112	WDAT	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15i	456.1	4198114	Radial Line Rev-Base Cost - Reliant Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15j	456.1	4198116	Radial Line Rev-Base Cost - Reliant Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15k	456.1	4198118	Radial Line Rev-O&M - AES Huntington Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15l	456.1	4198120	Radial Line Rev-O&M - Reliant Mandalay	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15m	456.1	4198122	Radial Line Rev-O&M - Reliant Coolwater	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15n	456.1	4198124	Radial Line Rev-O&M - Ormond Beach	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15o	456.1	4198126	High Desert Tie-Line Rental Rev	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15p	456.1	4198130	Inland Empire CRT Tie-Line EX	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	4
15q	456.1	4198910	Reliability Service Revenue - Non-PTO's	$ -	Other Ratemaking	$ -	$ -	$ -	$ -		$ -	$ -	$ -	6
16	**456.1 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
17	**FF-1 Total for Account 456.1 - Revenues from Trans. Of Electricity of Others, p300.22b (Must Equal Line 16)**			$ -										
18a														
19	**457.1 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
20	**FF-1 Total for Account 457.1 - Regional Control Service Revenues, p300.23b (Must Equal Line 19)**			$ -										
21a														
22	**457.2 Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
23	**FF-1 Total for Account 457.2- Miscellaneous Revenues, p300.24b (Must Equal Line 22)**			$ -										
	Edison Carrier Solutions (ECS)													
24a	417	4863130	ECS - Distribution Facilities	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24b	417	4862110	ECS - Dark Fiber	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24c	417	4862115	ECS - SCE Net Fiber	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24d	417	4862120	ECS - Transmission Right of Way	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24e	417	4862135	ECS - Wholesale FCC	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24f	417	4864115	ECS - EU FCC Rev	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24g	417	4862125	ECS - Cell Site Rent and Use (Active)	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24h	417	4862130	ECS - Cell Site Reimbursable (Active)	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
24i	417	4863120	ECS - Communication Sites	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24j	417	4863110	ECS - Cell Site Rent and Use (Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24k	417	4863115	ECS - Cell Site Reimbursable (Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24l	417	4863125	ECS - Micro Cell	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2
24m	417	4864120	ECS - End User Universal Service Fund Fee	$ -	GRSM	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2
25	**417 ECS Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
26	**417 Other**			$ -										
27	**FF-1 Total for Account 417 - Revenues From Nonutility Operations p117.33c (Must Equal Line 25 + 26)**			$ -										

Schedule 21
Revenue Credits

	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	$ -	$ -	$ -	$ -	A	$ -	$ -	$ -	2,9
28b	418.1		ESI (Gross Revenues - Passive)	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2,9
28c	418.1		Southern States Realty	$ -	GRSM	$ -	$ -	$ -	$ -	P	$ -	$ -	$ -	2, 15
28d	418.1		Mono Power Company	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	13
28e	418.1		Edison Material Supply (EMS)	$ -	Traditional OOR	$ -	$ -	$ -	$ -		$ -	$ -	$ -	7, 17
29	**418.1 Subsidiaries Total**			$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	
30	**418.1 Other (See Note 16)**			$ -										
31	**FF-1 Total for Account 418.1 -Equity in Earnings of Subsidiary Companies, p117.36c (Must Equal Line 29 + 30)**			$ -										
32			**Totals**	$ -		$ -	$ -	$ -	$ -		$ -	$ -	$ -	

Line			Calculation
33	Ratepayers' Share of Threshold Revenue	$ -	= Line 32K
34	ISO Ratepayers' Share of Threshold Revenue	$ -	Note 11
35			
36	Total Active Incremental Revenue	$ -	= Sum Active categories in column L
37	Ratepayers' Share of Active Incremental Revenue	$ -	= Line 36D * 10%
38	Total Passive Incremental Revenue	$ -	= Sum Passive categories in column L
39	Ratepayers' Share of Passive Incremental Revenue	$ -	= Line 38D * 30%
40	Total Ratepayers' Share of Incremental Revenue	$ -	= Line 37D + Line 39D
41	ISO Ratepayers' Share of Incremental Revenue (%)	- %	see Note 11
42	ISO Ratepayers' Share of Incremental Revenue	$ -	= Line 40D * Line 41D
43	**Tot. ISO Ratepayers' Share NTP&S Gross Rev.**	$ -	= Line 34D + Line 42D

Line		Amount	Calculation
44	**Total Revenue Credits:**	$ -	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 = - % Source: ---

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 = - % Source: ---

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.

Schedule 22
Network Upgrade Credits and Interest Expense

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	$ -	See Note 1
2	Acct 252 Other	$ -	Line 3 - Line 1
3	Total Acct 252 - Customer Advances for Construction	$ -	FF1 113.56d
	2) End of Year Balances: (Note 2)		
4	Outstanding Network Upgrade Credits Recorded in FERC Acct 252	$ -	See Note 3
5	Acct 252 Other	$ -	Line 6 - Line 4
6	Total Acct 252 - Customer Advances for Construction	$ -	FF1 113.56c
7	Average Outstanding Network Upgrade Credits Beginning and End of Year	$ -	(Line 1 + Line 4) / 2
8	Interest On Network Upgrade Credits Recorded in FERC Acct 242	$ -	See Note 4
9	Acct 242 Other	$ -	Line 10 - Line 8
10	Total Acct 242 - Miscellaneous Current and Accrued Liabilities	$ -	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.

Schedule 23
Regulatory Assets and Liabilities

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

Line

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

Line		Prior Year Amount	Calculation or Source
12			
13			
14	Other Regulatory Assets/Liabilities (EOY):	$ -	Sum of Column 2 below
15	Other Regulatory Assets/Liabilities (BOY/EOY average):	$ -	Avg. of Sum of Cols. 1 and 2 below
16	Amortization and Regulatory Debits/Credits:	$ -	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:	$ -	$ -	$ -	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.

Schedule 24
CWIP TRR

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:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 80
2	Devers to Colorado River:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 106
3	South of Kramer:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 132
4	West of Devers:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 158
5	Red Bluff:	$ -	$ -	$ -	10-CWIP, Lines 13, 14, 184
6	Whirlwind Sub Expansion:	$ -	$ -	$ -	10-CWIP, Lines 27, 28, 210
7	Colorado River Sub Expansion:	$ -	$ -	$ -	10-CWIP, Lines 27, 28, 236
8		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 262
9		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 288
10		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 314
11		$ -	$ -	$ -	10-CWIP, Lines 27, 28, 304
12	Totals:	$ -	$ -	$ -	Sum of Lines 1 to 11

b) Return:

Line		EOY Amount	Average Amount	Source
13	CWIP Amount:	$ -	$ -	Line 12
14	Cost of Capital Rate:	- %	- %	1-BaseTRR, Line 54
15	Cost of Capital:	$ -	$ -	Line 13 * Line 14

c) Income Taxes

Line		EOY Amount	Average Amount	Source
16	CWIP Amount:	$ -	$ -	Line 12
17	Equity ROR w Preferred Stock ("ER"):	- %	- %	1-BaseTRR, Line 55
18	Composite Tax Rate:	- %	- %	1-BaseTRR, Line 59
19	Income Taxes:	$ -	$ -	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 =	$ -	15-IncentiveAdder, Line 3

1) Tehachapi

Line		EOY Amount	Average Amount	
25	Tehachapi CWIP Amount:	$ -	$ -	Line 1
26	ROE Adder %:	- %	- %	15-IncentiveAdder, Line 5
27	ROE Adder $:	$ -	$ -	Formula on Line 32

2) Devers to Colorado River

Line		EOY Amount	Average Amount	
28	DCR CWIP Amount:	$ -	$ -	Line 2
29	ROE Adder %:	- %	- %	15-IncentiveAdder, Line 6
30	ROE Adder $:	$ -	$ -	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:	$ -	$ -	Line 15
34	Income Taxes:	$ -	$ -	Line 19
35	ROE Adder Tehachapi:	$ -	$ -	Line 27
36	ROE Adder DCR:	$ -	$ -	Line 30
37	FF&U:	$ -	$ -	Note 1
38	Total:	$ -	$ -	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:	$ -	$ -	$ -	$ -	$ -	Note 2
40	Devers to Colorado River:	$ -	$ -	$ -	$ -	$ -	Note 2
41	South of Kramer:	$ -	$ -	$ -	$ -	$ -	Note 2
42	West of Devers:	$ -	$ -	$ -	$ -	$ -	Note 2
43	Red Bluff:	$ -	$ -	$ -	$ -	$ -	Note 2
44	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 2
45	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 2
46		$ -	$ -	$ -	$ -	$ -	Note 2
47		$ -	$ -	$ -	$ -	$ -	Note 2
48		$ -	$ -	$ -	$ -	$ -	Note 2
49		$ -	$ -	$ -	$ -	$ -	Note 2
50	Totals:	$ -	$ -	$ -	$ -	$ -	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:	$ -	$ -	$ -	$ -	$ -	Note 3
52	Devers to Colorado River:	$ -	$ -	$ -	$ -	$ -	Note 3
53	South of Kramer:	$ -	$ -	$ -	$ -	$ -	Note 3
54	West of Devers:	$ -	$ -	$ -	$ -	$ -	Note 3
55	Red Bluff:	$ -	$ -	$ -	$ -	$ -	Note 3
56	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 3
57	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	$ -	Note 3
58		$ -	$ -	$ -	$ -	$ -	Note 3
59		$ -	$ -	$ -	$ -	$ -	Note 3
60		$ -	$ -	$ -	$ -	$ -	Note 3
61		$ -	$ -	$ -	$ -	$ -	Note 3
62	Totals:	$ -	$ -	$ -	$ -	$ -	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:	$ -	Line 12, Col 3
64	AFCRCWIP:	- %	2-IFPTRR, Line 16
65	CWIP component of IFPTRR without FF&U:	$ -	Line 63 * Line 64
66	FF&U:	$ -	Line 65 * (28-FFU, L5 FF Factor + U Factor)
67	CWIP component of IFPTRR including FF&U:	$ -	Line 65 + Line 66

b) Individual Project Contribution

	Project	Amount wo FF&U	Amount with FF&U	Source
68	Tehachapi:	$ -	$ -	Note 4
69	Devers to Colorado River:	$ -	$ -	Note 4
70	South of Kramer:	$ -	$ -	Note 4
71	West of Devers:	$ -	$ -	Note 4
72	Red Bluff:	$ -	$ -	Note 4
73	Whirlwind Sub Expansion:	$ -	$ -	Note 4
74	Colorado River Sub Expansion:	$ -	$ -	Note 4
75		$ -	$ -	Note 4
76		$ -	$ -	Note 4
77		$ -	$ -	Note 4
78		$ -	$ -	Note 4
79	Totals:	$ -	$ -	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:	$ -	Sum Line 33 to 36
81	CWIP component of IFPTRR wo FF&U:	$ -	Line 65
82	Total without FF&U:	$ -	Line 80 + Line 81
83	FF Factor:	- %	28-FFU, Line 5
84	U Factor:	- %	28-FFU, Line 5
85	Franchise Fees Amount:	$ -	Line 82 * Line 83
86	Uncollectibles Amount:	$ -	Line 82 * Line 84
87	Total Contribution of CWIP to Retail Base TRR:	$ -	Line 82 + Line 85 + Line 86
88	Total Contribution of CWIP to Wholesale Base TRR:	$ -	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:	$ -	$ -	$ -	$ -	Note 5
90	Devers to Colorado River:	$ -	$ -	$ -	$ -	Note 5
91	South of Kramer:	$ -	$ -	$ -	$ -	Note 5
92	West of Devers:	$ -	$ -	$ -	$ -	Note 5
93	Red Bluff:	$ -	$ -	$ -	$ -	Note 5
94	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	Note 5
95	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	Note 5
96		$ -	$ -	$ -	$ -	Note 5
97		$ -	$ -	$ -	$ -	Note 5
98		$ -	$ -	$ -	$ -	Note 5
99		$ -	$ -	$ -	$ -	Note 5
100	Totals:	$ -	$ -	$ -	$ -	

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:	$ -	$ -	$ -	$ -	Note 6
102	Devers to Colorado River:	$ -	$ -	$ -	$ -	Note 6
103	South of Kramer:	$ -	$ -	$ -	$ -	Note 6
104	West of Devers:	$ -	$ -	$ -	$ -	Note 6
105	Red Bluff:	$ -	$ -	$ -	$ -	Note 6
106	Whirlwind Sub Expansion:	$ -	$ -	$ -	$ -	Note 6
107	Colorado River Sub Expansion:	$ -	$ -	$ -	$ -	Note 6
108		$ -	$ -	$ -	$ -	Note 6
109		$ -	$ -	$ -	$ -	Note 6
110		$ -	$ -	$ -	$ -	Note 6
111		$ -	$ -	$ -	$ -	Note 6
112	Totals:	$ -	$ -	$ -	$ -	

Notes:
1) (Sum Lines 33 to 36) * (FF + U Factors from 28-FFU) for Prior Year TRR
(Sum Lines 33~~4~~ to 36~~7~~) * (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.

Schedule 25
Wholesale Differences to Base TRR

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	- %	1
13	Prior Year		-	2
14	Wholesale Rate Base Difference for Prior Year		$ -	3
15	Wholesale Rate Base Adjustment	Line 14 * Line 12	$ -	

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	$ -
17	Composite Tax Rate ("CTR")	1-BaseTRR L 59	- %
18	Tax Gross Up Factor	(1/(1-CTR))	---
19	Wholesale South Georgia		
20	Income Tax Adjustment to the TRR:	- Line 16 * Line 18	$ -

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

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

Schedule 25
Wholesale Differences to Base TRR

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

3) Calculation of the Wholesale Difference to the Base TRR

		Source	**Value**	
39	Wholesale Rate Base Adjustment	Line 15	$ -	
40	Expense Difference	Line 38	$ -	
41	Uncollectibles Expense -- Prior Year TRR	- 1-Base TRR, L 80	$ -	
42	Uncollectibles Expense -- IFPTRR	- 2-IFPTRR, L 80	$ -	
43	Subtotal:	Sum Line 39 to Line 42	$ -	
44	Franchise Fee Exclusion		$ -	Note 4
45	Wholesale Difference to the Base TRR:	Line 43 + Line 44	$ -	

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.
6) If appropriate, additional expenses may be excluded from the Wholesale Base TRR

Schedule 26
Tax Rates

Income Tax Rates

1) Federal Income Tax rate — Inputs are shaded yellow

Line	Rate Year	Federal Income Tax Rate ("FITR")		Source
1	-	- %	Note 1, Note 4	
2				
3	**2) Composite State Income Tax Rate**			
4				
5		State		
6	Rate	Income Tax		
7	Year	Rate ("SITR")		Source
8	-	- %	Note 2	
9				
10				
11				

Line	3) Capitalized Overhead portion of Electric Payroll Tax Expense	Amount
12	**3) Capitalized Overhead portion of Electric Payroll Tax Expense**	
13		
14	Total Electric Payroll Tax Expense (From 1-BaseTRR, Line 31)	$ -
15	Capitalization Rate (Note 3)	- %
16	Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 * Line 15)	$ -
17	Non-Capitalized Overhead portion of Electric Payroll Tax Expense (Line 14 - Line 16)	$ -

Notes:

1) Federal Source Statute: ---

2) California State Source Statue: ---

3) Capitalization Rate approved in: ---
For the following Prior Years: ---

4) In the event that either the Federal or State Income Tax Rate applicable to the Rate Year differs from that in effect during the Prior Year, the True Up TRR for the Prior Year will be calculated utilizing the same Formula Rate Spreadsheet except for the Income Tax rate(s). The difference between the True Up TRR calculated in such workpaper using the Income Tax Rates that were in effect during the Prior Year and the True Up TRR otherwise calculated by this formula shall be entered as a One Time Adjustment on Schedule 3, ensuring that the Formula Spreadsheet correctly calculates the True Up TRR for the Prior Year to be based on the Income Tax Rate(s) that were in effect during that year. For the Prior Years of 2016 and 2017, both of which will have Income Tax Rates that differ between the Prior Year and the Rate Year due to the passage of the 2017 Tax Cuts and Jobs Act, this provision will be implemented as part of the Section 6 of the Formula Rate Protocols, which will calculate the True Up TRR for those years based on a Federal Income Tax Rate of 35%.

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	$ -
2	Total Wages and Salaries		FF1 354.28b	$ -
3	Less Total A&G Wages and Salaries		FF1 354.27b	$ -
4	Total Wages and Salaries wo A&G		Line 2 - Line 3	$ -
5	Total NOIC (Non-Officer Incentive Compensation)		20-AandG, Note 2	$ -
6	Less A&G NOIC		20-AandG, Note 2	$ -
7	NOIC wo A&G NOIC		Line 5 - Line 6	$ -
8	Total non-A&G W&S with NOIC		Line 4 + Line 7	$ -
9	Transmission Wages and Salary Allocation Factor		Line 1 / Line 8	- %
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	$ -
15	Distribution Plant - ISO		7-PlantStudy, Line 30	$ -
16	Total Electric Miscellaneous Intangible Plant		6-PlantInService, Line 21, C2	$ -
17	Electric Miscellaneous Intangible Plant - ISO		Line 16 * Line 9	$ -
18	Total General Plant		6-PlantInService, Line 21, C1	$ -
19	General Plant - ISO		Line 18 * Line 9	$ -
20	Total Plant In Service		FF1 207.104g	$ -
21				
22	Transmission Plant Allocation Factor		(L14 + L15 + L17 + L19) / L20	- %
23				

Line		Values	Notes	Applied to Accounts
24	**3) Schedule 19 "Percent ISO" Allocation Factors (Input values are from SCE Records)**			
25				
26	a) Line Miles	**Values**	**Notes**	**Applied to Accounts**
27	ISO Line Miles	---		563 --Overhead Line Expenses - Allocated
28	Non-ISO Line Miles	---		567 - Line Rents - Allocated
29	Total Line Miles	---	= L27 + L28	571 - Maintenance of Overhead Lines - Allocated
30	Line MIles Percent ISO	- %	= L27 / L29	
31				
32	b) Underground Line Miles	**Values**	**Notes**	**Applied to Accounts**
33	ISO Underground Line Miles	---		564 - Underground Line Expense
34	Non-ISO Underground Line Miles	---		572 - Maintenance of Underground Transmission Lines
35	Total Undergound Line Miles	---	= L33 + L34	
36	Underground Line MIles Percent ISO	- %	= L33 / L35	
37				
38	c) Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
39	ISO Circuit Breakers	---		All Other Non 0% or 100% Transmission O&M Accounts
40	Non-ISO Breakers	---		
41	Total Circuit Breakers	---	= L39 + L40	
42	Circuit Breakers Percent ISO	- %	= L39 / L41	
43				
44	d) Distribution Circuit Breakers	**Values**	**Notes**	**Applied to Accounts**
45	ISO Distribution Circuit Breakers	---		582 - Station Expenses
46	Non-ISO Distribution Circuit Breakers	---		590 - Maintenance Supervision and Engineering
47	Total Distribution Circuit Breakers	---	= L45 + L46	591 - Maintenance of Structures
48	Distribution Circuit Breakers Percent ISO	- %	= L45 / L47	592 - Maintenance of Station Equipment

Schedule 28
FF and U

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	---	---	---	- %	---
2	---	---	---	- %	---

2) Approved Uncollectibles Expense Factor(s)

	From	To	Days in Prior Year	U Factor	Reference
3	---	---	---	- %	---
4	---	---	---	- %	---

3) FF and U Factors

	Prior Year	FF Factor	U Factor	Notes
5	---	- %	- %	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:	- %	((L1 FF Factor * L1 Days) + (L2 FF Factor * L2 Days))/(L1+L2 Days)
Prior Year U Factor:	- %	((L3 U Factor * L3 Days) + (L4 U Factor * L4 Days))/(L3+L4 Days)

Schedule 29
Wholesale TRRs

CALCULATION OF SCE WHOLESALE HIGH AND LOW VOLTAGE TRRS

Inputs are shaded yellow

Line	TRR Values		Notes	Source
1	$ -	= Wholesale Base TRR		1-BaseTRR, Line 89
2	$ -	= Total Wholesale TRBAA	Note 1	---
3	$ -	= HV Wholesale TRBAA		---
4	$ -	= LV Wholesale TRBAA		---
5	$ -	= Total Standby Transmission Revenues	Note 2	SCE Retail Standby Rate Revenue
6	- %	= HV Allocation Factor		31-HVLV, Line 37
7	- %	= LV Allocation Factor		31-HVLV, Line 37

Calculation of Total High Voltage and Low Voltage components of Wholesale TRR

		Col 1 TOTAL	Col 2 High Voltage	Col 3 Low Voltage	Source
8	Wholesale Base TRR:	$ -	$ -	$ -	See Note 3
9	CWIP Component of Wholesale Base TRR:	$ -	$ -	$ -	See Note 4
10	Non-CWIP Component of Wholesale Base TRR:	$ -	$ -	$ -	See Note 5
11	Wholesale TRBAA:	$ -	$ -	$ -	Lines 2 to 4
12	Less Standby Transmission Revenues:	$ -	$ -	$ -	See Note 6
13	Components of Wholesale Transmission Revenue Requirement:	$ -	$ -	$ -	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: ---
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.

Schedule 30
Wholesale Rates

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 =	$	-		29-WholesaleTRRs, Line 13, C3
2	Gross Load =		---	MWh	32-Gross Load, Line 43
3	Low Voltage Access Charge =	$	-	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 =	$	-		29-WholesaleTRRs, Line 13, C2
5	Gross Load =		---	MWh	32-Gross Load, Line 43
6	High Voltage Utility-Specific Rate =	$	-	per kWh	Line 4 / (Line 5 * 1000)

Calculation of High Voltage Existing Contracts Access Charge:

Line					Source
7	HV Wholesale TRR =	$	-		29-WholesaleTRRs, Line 13, C2
8	Sum of Monthly Peak Demands:		---	MW	32-Gross Load, Line 54
9	HV Existing Contracts Access Charge:	$	-	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.

Schedule 31
High and Low Voltage Gross Plant

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	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
3	LV Transmission Lines	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
4	**Total Transmission Lines (L 2 + L 3):**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5									
6	**Substations:**								
7	HV Substations (>= 200 kV)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	Straddle Subs (Cross 200 kV bound.):	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	LV Substations (Less Than 200kV)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	**Total all Substations (L7 + L8 + L9)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11									
12	**Total Lines and Substations**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13									
14									

Line		High Voltage	Low Voltage	Total	Notes:
15	Gross Plant that can directly be determined to be HV or LV:				
16					
17					
18	Land	$ -	$ -	$ -	From above Line 12
19	Structures	$ -	$ -	$ -	From above Line 12
20	Total Determined HV/LV:	$ -	$ -	$ -	Sum of lines 18 and 19
21	Gross Plant Percentages (Prior Year):	- %	- %		Percent of Total
22					
23	Straddling Transformers	$ -	$ -	$ -	Straddling Transformers split by Gross Plant Percentages on Line 21
24	Abandoned Plant (BOY)	$ -	$ -	$ -	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	$ -	$ -	$ -	Line 20 + Line 23 + Line 24
26					
27					

Line		High Voltage	Low Voltage	Total	Notes:
28	**B) Gross Plant Percentage for the Rate Year:**				
29					
30					
31					
32	Total HV and LV Gross Plant for Prior Year	$ -	$ -	$ -	Line 25
33	In Service Additions in Rate Year:	$ -	$ -	$ -	13-Month Average: 16-PlantAdditions, Line 25, Cols 7 (for Total) and 12 (for LV). HV = C7 - C12.
34	CWIP in Rate Year	$ -	$ -	$ -	13 Month Average: 10-CWIP, Line 54, Col. 8
35	Total HV and LV Gross Plant for Rate Year	$ -	$ -	$ -	Line 32 + Line 33 + Line 34
36					
37	HV and LV Gross Plant Percentages:	- %	- %		Percent of Total on Line 35
38	(HV Allocation Factor and				
39	LV Allocation Factor)				

Schedule 32
Gross Load

Calculation of Forecast Gross Load

Line		MWh	Calculation	Source
1	SCE Retail Sales at ISO Grid level:	---		Note 1
2	Pump Load forecast:	---		Note 2
3	Pump Load True-Up:	---		Note 4
4~~3~~	Forecast Gross Load:	---	Line 1 + Line 2 + Line 3	Sum of above
5~~4~~	Forecast 12-CP Retail Load:	---		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.
4) The Pump Load True-Up value is equal to actual recorded less forecast Pump Load for the Prior Year.

Calculation of SCE Retail Transmission Rates

		Source	
Retail Base TRR:	$ -	1-BaseTRR WS, Line 86	**Input cells are shaded yellow**

1) Derivation of "Total Demand Rate" and "Total Energy Rate":

Line	CPUC Rate Group	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)	Recorded Billing Determinants: to be applied to the Supplemental kW demand charges, and the Contracted Standby 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	- %	$ -						---	$ -					
1b	TOU-GS-1	- %	$ -						---	$ -					
$1b_2$	TOU-GS-1 continued								---		---	---	---	---	Notes 9,10
1c	TC-1	- %	$ -						---	$ -					
1d	TOU-GS-2	- %	$ -						---		$ -				
1e	TOU-GS-3	- %	$ -						---		$ -				
1f	TOU-8-SEC	- %	$ -						---		$ -				
1g	TOU-8-PRI	- %	$ -						---		$ -				
1h	TOU-8-SUB	- %	$ -						---		$ -				
1i	TOU-8-Standby-SEC	- %	$ -						---		$ -				
1j	TOU-8-Standby-PRI	- %	$ -						---		$ -				
1k	TOU-8-Standby-SUB	- %	$ -						---		$ -				
1l	TOU-PA-2	- %	$ -						---		$ -				
1m	TOU-PA-3	- %	$ -						---		$ -				
1n	Street Lighting	- %	$ -						---	$ -					
1o	---								---						
2	Totals:	- %	$ -	---	---	---	---	---	---						

3

4

5 **2) Determination of Demand Rates for Large Power (TOU-8) Rate Groups**

Line	CPUC Rate Group	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	$ -	---	$ -		TOU-8-SEC	$ -	---	$ -
9b	TOU-8-Standby-PRI	$ -	---	$ -		TOU-8-PRI	$ -	---	$ -
9c	TOU-8-Standby-SUB	$ -	---	$ -		TOU-8-SUB	$ -	---	$ -
9d	---					---			
10									

Line		Col 1	Col 2	Col 3	Col 4	Col 5	Col 6	Col 7	Col 8	Col 9	Col 10	Col 11
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	Col 11
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		= Line16:Col2 / (Line1:Col8 * 10^6)
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	Transportation Electrification (TE) Energy Charge - $/kWh
16a	Domestic	$ -	$ -			$ -						
16b	TOU-GS-1	$ -	$ -	$ -		$ -	$ -	$ -	$ -	$ -	Note 15	$ -
16c	TC-1	$ -	$ -			$ -						
16d	TOU-GS-2	$ -	$ -	$ -			$ -	$ -			Note 16	$ -
16e	TOU-GS-3	$ -	$ -	$ -			$ -	$ -				$ -
16f	TOU-8-SEC	$ -	$ -				$ -					$ -
16g	TOU-8-PRI	$ -	$ -				$ -					$ -
16h	TOU-8-SUB	$ -	$ -				$ -					$ -
16i	TOU-8-Standby-SEC	$ -	$ -	$ -			$ -	$ -				
16j	TOU-8-Standby-PRI	$ -	$ -	$ -			$ -	$ -				
16k	TOU-8-Standby-SUB	$ -	$ -	$ -			$ -	$ -				
16l	TOU-PA-2	$ -	$ -	$ -			$ -	$ -	$ -	$ -	Note 17	
16m	TOU-PA-3	$ -	$ -	$ -			$ -	$ -				
16n	Street Lighting	$ -	$ -			$ -						
16o	---											
17	Totals:	$ -	$ -	$ -								
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:Col10~~9~~
15) Applicable to time-of-use schedules within the GS-1 rate group
16) Rates associated with Rate Groups GS-2 and TOU-GS-3 are calculated on a combined basis, so that the rate is the sum of the combined Revenue Associated with Supplemental Demand or Energy in Column 2 (line 16d and 16e) divided by the sum of the sum of the Billing Determinants in Column 8 (Line 1d and 1e).
17) Applicable to the optional schedules that contain horse power charge such as PA-1
18) 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, TOU-D-T-CPP, TOU-D (Options 4-9 PM, 5-8 PM, PRIME, and CPP)
26b	TOU-GS-1	Includes Schedules GS-1, TOU-EV-3, TOU-EV-7 (Options D and E), and TOU-GS-1 (Options E, ES, D, LG, C, 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	TOU-GS-2	Includes Schedules GS-2, TOU-EV-4, TOU-EV-8, and TOU-GS-2 (Options D, E, A, B, R, RTP, CPP, Standby, GS-APS, GS-APS-E, and ME).
26e	TOU-GS-3	Includes Schedules TOU-GS-3-CPP, TOU-EV-8, and TOU-GS-3 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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, TOU-EV-9, and TOU-8 (Options D, E, 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 (Options D, LG, A, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26j	TOU-8-Standby-PRI	Includes Schedules TOU-8-Standby (Options D, LG, A, A2, B, RTP, TOU-BIP, GS-APS, GS-APS-E, and ME).
26k	TOU-8-Standby-SUB	Includes Schedules TOU-8-Standby (Options D, LG, 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 (Options D, E, 4-9 PM, 5-8 PM, 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 (Options D, E, 4-9 PM, 5-8 PM, A, B, RTP, SOP-1, SOP-2, Standby, and AP-I).
26n	Street Lighting	Includes Schedules AL-2, AL-2-B, AL-2-F, 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 18	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**				**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				---			---	---	---	---	- %
35b	TOU-GS-1				---			---	---	---	---	- %
35c	TC-1				---			---	---	---	---	- %
35d	TOU-GS-2				---			---	---	---	---	- %
35e	TOU-GS-3				---			---	---	---	---	- %
35f	TOU-8-SEC				---			---	---	---	---	- %
35g	TOU-8-PRI				---			---	---	---	---	- %
35h	TOU-8-SUB				---			---	---	---	---	- %
35i	TOU-8-Standby-SEC				---			---	---	---	---	- %
35j	TOU-8-Standby-PRI				---			---	---	---	---	- %
35k	TOU-8-Standby-SUB				---			---	---	---	---	- %
35l	TOU-PA-2				---			---	---	---	---	- %
35m	TOU-PA-3				---			---	---	---	---	- %
35n	Street Lighting				---			---	---	---	---	- %
35o	---											
36	Totals:	---	---	---	---	---	---	---	---	---	---	- %

Schedule 34
Unfunded Reserves

Determination of Unfunded Reserves

Line		Reference			
1					
2					
3					**Prior Year**
4		**Reference**			**Amount**
5					
6	**Unfunded Reserves (EOY):**	(Line 17, Col 2)			$ -
7	**Unfunded Reserves (Average BOY/EOY):**	(Line 17, Col 3)			$ -
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)	$ -	$ -	$ -
15	Provision for Vac/Sick Leave	(Line 29)	$ -	$ -	$ -
16	Provision for Supplemental Executive Retirement Plan	(Line 36)	$ -	$ -	$ -
17	Totals:	(Line 14 + Line 15 + Line 16)	$ -	$ -	$ -
18					
19	**Calculations**				
20					Average
21	**Injuries and Damages**		BOY	EOY	BOY/EOY
22	Injuries and Damages - Note 1 ~~Acct. 2251010~~	Company Records - Input (Negative)	$ -	$ -	
23	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
24	ISO Transmission Rate Base Applicable	(Line 22 x Line 23)	$ -	$ -	$ -
25					
26	**Vacation Leave**				
27	Vacation and Personal Time Accruals - Acct. 2350080	Company Records - Input (Negative)	$ -	$ -	
28	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
29	ISO Transmission Rate Base Applicable	(Line 27 x Line 28)	$ -	$ -	$ -
30					
31	**Supplemental Executive Retirement Plan**				
32	Supplemental Executive Retirement Plan	Company Records - Input (Negative)	$ -	$ -	
33	Times:	Applicable Rate Base Percentage	50%	50%	
34	Sub-Total Supplemental Executive Retirement Plan	(Line 32 x Line 33)	$ -	$ -	
35	Transmission Wages and Salary Allocation Factor	(27-Allocators, Line 9)	- %	- %	
36	ISO Transmission Rate Base Applicable	(Line 34 x Line 35)	$ -	$ -	$ -

Notes:

1) Includes any Unfunded Reserves relating to accrued expenses included in Account 925 "Injuries and Damages", reduced for any expected offsetting payments.