UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

SAN DIEGO GAS & ELECTRIC COMPANY) DOCKET NO. ER13-___-000

SAN DIEGO GAS & ELECTRIC COMPANY'S

TRANSMISSION OWNER TARIFF

TO4 FORMULA

VOLUME 2

FEBRUARY 15, 2013

Exhibit No. SDG-1

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BEFORE THE
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San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
JAMES P. AVERY
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

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EXHIBIT NO. SDG-1

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I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is James P. Avery. My business address is 8330 Century Park Court, San Diego, CA 92123.

Q2. By whom and in what capacity are you employed?

A2. I am employed by San Diego Gas & Electric Company (SDG&E), as Senior Vice President – Power Supply.

Q3. What are your duties and responsibilities?

A3. I oversee the Company's Resource, Distribution and Transmission Planning, Electric & Fuel Procurement, Electric Generation and Smart Grid Policy and Initiatives.

Q4. Please describe your educational background.

A4. I attended Manhattan College, New York City, New York, graduating with a Bachelor of Engineering Degree in Electrical Engineering with a major field of study in Electric Power. Prior to that, I attained an Associate's Degree in the Field of Electrical Engineering from New York City Community College.

Q5. Please state your work experience prior to the work you are doing today.

A5. Prior to joining SDG&E in 2001, I was a consultant at R.J. Rudden Associates, one of the nation's leading management and economic consulting firms specializing in energy and utility matters. Prior to that, I functioned as the chief executive officer of the electric and gas operations at Citizens Utilities Company, a multi-service organization that provided electric, gas, telecommunication, water and wastewater services in over 20 states across the nation. I am currently on the board of directors of the California Power Exchange, CleanTech San Diego and I am the Chairman of the California Transmission Planning Group. I have also served on the board of directors of R.J. Rudden Associates and Vermont Electric Power Company, a transmission-only company serving the state of Vermont. In addition, I have held various positions at American Electric Power Service Corporation.

Q6. Have you ever testified before the Federal Energy Regulatory Commission (Commission or FERC)?

A6. Yes, including in the proceeding in which the Commission adopted SDG&E's currently-effective Transmission Owner (TO) Formula (TO3), which is due to expire August 31, 2013 (Docket No. ER07-284-000).

II. PURPOSE

Q7. What is the purpose of your testimony?

A7. As a senior executive with broad policy responsibilities for SDG&E, the purpose of my testimony is to explain why it is sound policy for SDG&E to continue its formulaic approach to ratemaking by proposing its fourth TO Formula (TO4).

In general terms, to provide a seamless transition between TO3 and TO4, SDG&E proposes to implement its TO4 Formula, effective September 1, 2013, at the expiration of the TO3 Formula on August 31, 2013. The TO4 Formula continues many, but not all, aspects of the TO3 Formula. I will highlight the key features of the TO4 Formula, as well as the key differences between the TO3 Formula and the TO4 Formula below. SDG&E Witness Ed Lucero will discuss them in greater detail in his testimony (Exhibit SDG-2).

Q8. Please summarize the key topics of your testimony.

A8. In addition to the Introduction and Purpose discussed above in Sections I and II, the remainder of my testimony addresses the following topics:

III. Description of Key Features of the TO4 Formula

IV. Overview of Testimony of SDG&E Witnesses

V. Importance of Continuing Formulaic Ratemaking in TO 4

- Customer and Company Benefits
- Other Specific Benefits

VI. Commission Support for Transmission Formulas

VII. Rationale for the Indefinite Term of the TO4 Formula

VIII. TO4 Equations Will Permit SDG&E to Incorporate Approved Incentives

IX. Continuation of the 50 Basis Point Adder for Participating in the California Independent System Operator Corporation (CAISO)

X. Proposed Return on Equity (ROE)

XI. Direct Assignment of Function-Specific Costs Recorded in Accounts 920 through 935

III. DESCRIPTION OF KEY FEATURES OF THE TO4 FORMULA

Q9. Please briefly describe this Filing.

A9. As noted previously, the TO4 Formula is proposed to become effective September 1, 2013, immediately following the termination of the TO3 Formula. The TO 4 will remain in effect indefinitely, with SDG&E retaining right to terminate or modify the formula at its election under Section 205 of the Federal Power Act (FPA).

Q10. How does the TO4 Formula differ from the TO3 Formula?

A10. The TO4 Formula differs from the currently-effective TO3 Formula primarily with respect to: (1) the timing of Rate Effective Periods, (2) inclusion of equations to incorporate incentive rate treatment that the Commission may approve during the term of the TO4 Formula and (3) providing SDG&E with the opportunity to directly assign costs attributable to Function-Specific events or occurrences recorded in Administrative and General (A&G) Accounts 920 through 935, to the transmission function, consistent with cost causation principles.

Q11. Please continue.

A11. The key differences between TO3 and TO4 may be summarized as follows:

1. The effective date of the various cycles, *i.e.*, September 1 will be the first month of the proposed Rate Effective Dates for the first two cycles (September 1, 2013 through August 31, 2014 and September 1, 2014 through December 31, 2015) and January 1 will be the proposed first month for Rate Effective Dates for the remaining cycles under the TO4 Formula, commencing 2016. The Rate Effective Dates for TO3 were September 1 of each year.

2. TO4 will contain equations to permit SDG&E to incorporate project-specific incentive rate treatments provided for in the Order No. 697 series of orders for qualifying transmission facilities that ensure reliability or lower the cost of delivered power by reducing transmission congestion that the Commission may approve for SDG&E during the term of the TO4 Formula. As Mr. Lucero further explains, while the TO4 Formula will include mechanisms to incorporate alternative rate structures specific to future transmission projects, *i.e.*, incentives, those mechanisms will not be triggered without prior Commission approval in connection with those projects. Under the TO3 Settlement, SDG&E agreed to forgo filing for incentives for all projects except the Sunrise Powerlink Project (Sunrise) during the term of the TO3 Formula. For Sunrise, SDG&E agreed to forgo incentives permanently. Thus, there was no need to include similar mechanisms in the TO3 Formula.

3. TO4 provides for a bifurcated ratemaking approach to costs recorded in Accounts 920 through 935. Under TO3, costs booked to those accounts would be allocated based on a labor-ratio basis, which assigns approximately 85% of recorded costs to the Distribution Function and 15% to the Transmission Function. While labor ratios can be appropriated for allocating many types of costs, for certain costs that are directly and uniquely tied to the Transmission Function, use of a labor-ratio allocator produces unreasonable results. Accordingly, in TO4 SDG&E proposes to segment costs within those accounts and directly assign costs related to certain specified types of events or occurrences to its Transmission Function, consistent with costs causation principles. For all other A&G costs recorded to those accounts that do not lend themselves to direct assignment, SDG&E proposes to allocate those costs on the basis of labor ratios. The TO3 Formula did not expressly provide for the direct assignment of any A&G costs recorded to those accounts. SDG&E Witness Michelle Somerville discusses this issue in detail. (Exhibit No. SDG-5).

I touch on these points later in my testimony.

IV. OVERVIEW OF THE TESTIMONY OF SDG&E WITNESSES

Q12. Please summarize the testimony that the other witnesses are submitting in this proceeding.

A12. In addition to my own, SDG&E is submitting testimony by nine (9) other witnesses in this proceeding. Their testimony may be summarized as follows (order of witnesses needs to be revised):

- Mr. Ed Lucero provides a general overview of the filing from a technical perspective in (Exhibit No. SDG-2).
- Ms. Leonor Sanchez sponsors Appendix VIII which is SDG&E's Tariff embodying the TO4 Formula. (Exhibit No. SDG-3).
- Ms. Lolit Tanedo describes the Base Period Revenues and sponsors Statements (Exhibit No. SDG-4).
- Ms. Michelle Somerville discusses the mechanics of allocating or directly assigning specified types of costs recorded in Accounts 920 through 935 to SDG&E's Transmission Function, consistent with cost causation principles. Ms. Somerville explains the basis for establishing the direct assignment monetary trigger of $5Million for Account 925 and $1Million for all other A&G accounts. (Exhibit No. SDG-5).Ms. Somerville also discusses the bases for determining whether and under what circumstances transmission related electric miscellaneous intangible plant should be allocated using a labor allocator or directly assigned consistent with cost causation principles.
- Mr. Raulin Farinas describes the True-Up Adjustment and the high voltage/low voltage methodology mandated by the CAISO Tariff underlying SDG&E's Base Transmission Revenue Requirements. (Exhibit No. SDG-6)
- Mr. John Jenkins describes the Forecast Period capital additions. (Exhibit No. SDG-7).
- Mr. Robert Wieczorek supports SDG&E's changed depreciation rate. (Exhibit No. SDG-8).
- Dr. Roger A. Morin recommends a return on common equity (ROE) for the jurisdictional electric transmission operations of SDG&E that he concludes would: (1) be fair to ratepayers, (2) allow SDG&E to attract capital on reasonable terms, (3)

maintain its financial integrity and (4) be comparable to returns offered on comparable risk investments, and consistent with the Commission's policy objectives. (Exhibit No. SDG-9)

- Ms. Sandra Hrna discusses SDG&E's risk profile in (Exhibit No. SDG-10). Ms Hrna explains the importance of risk as a component of determining a just and reasonable return on equity and describes in detail the components of investment risk that SDG&E faces that distinguish it from the peer group. Investment risk is broken down into business, financial and regulatory risk.

V. IMPORTANCE OF CONTINUING FORUMLAIC RATEMAKING IN TO4

Q13. Why is it important for SDG&E to continue its transmission formula process under TO4?

A13. SDG&E has had two formulas, TO2 and TO3 and both have worked well. The Commission approved the Settlement adopting SDG&E's current TO3 Formula in 2007, in Docket ER07-284-000. SDG&E has filed six annual filings under its TO3 Formula, the most current in Docket ER12-2454-000 for Cycle 6 rates going into effect September 1, 2012. To better recognize the benefits of the formula, let me briefly discuss in general how the current TO3 formula process works, which is similar to how the TO4 formula process will work. Mr. Lucero in his testimony will discuss in more detail how the TO4 Formula process will work from a technical perspective.

Q14. Please describe the current TO3 Formula.

A14. The TO3 Formula, described in Appendix VIII of SDG&E's TO Tariff, consists of five (5) components: (1) Base Period, (2) True-Up (TU) Adjustment, (3) Interest TU Adjustment, (4) Forecast Period and (5) Rate Effective Period. Mr. Lucero discusses these components in greater detail.

Q15. Will SDG&E's TO4 Formula work in the same manner as TO3?

A15. Yes, although we are proposing certain changes summarized above and discussed in more detail below.

A. Customer and Company Benefits of the Formula

Q16. Please describe the customer and company benefits that have resulted during the time that SDG&E has operated under its annual formula, which will continue under TO4.

A16. The formula has conferred numerous benefits by promoting transparency and operational and planning flexibility. These points are discussed below.

1. Customer Transparency

Q17. How does the formulaic approach to ratemaking promote customer transparency?

A17. The formula provides customer transparency in several areas that include the following: One of the biggest benefits the formula provides to its customers and the California Public Utilities Commission (CPUC) staff is that it provides full transparency of SDG&E's annual transmission costs, which allows for closer review by the CPUC and other parties, in contrast to a Period 1 and Period 2 filing. Rates that are filed and go into effect based upon a Period 2 filing are subject to a tremendous amount of review and litigation relative to the forecasted costs used in Period 2. Formula rates, on the other hand, avoid this review and litigation because the formula only collects actual recorded costs in the Base Period and True-Up Adjustments. This means SDG&E collects only "actual recorded" costs at an authorized ROE, no more and no less.

- Both the Base Period and TU Adjustment are based upon recorded costs that are of public record and reflected in FERC Form 1, with related Form 1 pages included in the filing.
- A filing exhibit that reflects monthly transmission Forecast Plant additions in each cycle that in large part are pre-approved by the CAISO. Page references from the most current annual CAISO Transmission Expansion Plan are reflected in the exhibit that shows the CAISO approval of the various projects. These projects have undergone public review through an annual CAISO stakeholder Transmission Planning Process and are subsequently approved by CAISO management or the CAISO Board of Governors, as provided for under the CAISO Tariff and associated Business Practices Manual. Parties requested that SDG&E include this exhibit in its TO3 filings and SDG&E will continue to do so in TO4. SDG&E will also work with the CPUC to include language in the TO 4 Formula providing for the involvement of the CPUC in the CAISO's Annual Transmission Planning Process, consistent with the CAISO's Tariff.

- A filing exhibit that reflects Forecast Plant additions in each cycle and contains for information purposes the status of CPUC advice letters, Permits to Construct, or Certificates of Public Convenience and Necessity as these approval and permitting processes pertain to environmental and customer concerns with specific transmission projects. In TO3, SDG&E included this exhibit and will continue to include this exhibit in TO4.
- The Formula allows for a two month review period by third parties of the Draft Information Filing that SDG&E posts on its website. For Cycles 1 and 2 of TO4, the posting date will be June 15th and for the subsequent cycles, the posting date will be October 15th. In Section 5 below I describe the benefits and transparency of this two month review period to all parties.

2. Operational and planning flexibility provided to SDG&E by the formula

Q18. Please describe the operational and planning flexibility that SDG&E and its customers enjoy under the formula.

A18. A big advantage of the formula is that it provides prompt rate relief which in turn gives SDG&E the operational flexibility and incentive to invest in and energize critical transmission projects as soon as possible so that customers can reap the benefits of greater transmission reliability, lower congestion costs and enhanced electric service quality as promptly as possible. I describe several examples below.

One example of the Formula's flexibility in both the operational and planning areas dealt with SDG&E's recent Cycle 6 filing and the timing of the Sunrise project in service date shown in the Forecast Period. Sunrise is a $1.8 billion transmission project that was scheduled to go into service in mid 2012. The in-service date was contingent upon meeting certain construction deadlines and meeting ongoing environmental requirements that were required by various agencies. On June 15, 2012 when SDG&E posted its Cycle 6 Draft Informational filing for review by third parties, SDG&E estimated that the lion's share of the Sunrise project would go into service June 15 and developed an estimate of these costs for the Draft Information posting. However, because the in-service date of June 15 coincided with the beginning of the Formula's two-month review process, at the first technical conference to review the Draft

Informational Filing in early July 30, 2012, SDG&E was able to update the Sunrise numbers to actual recorded amounts for June 2012. As a result of this flexibility, SDG&E was able to pass on actual costs of the project to customers rather than estimated costs.

Another example relates to construction the Miguel-Mission #2 project consisting of a second 230 kV transmission line from Miguel substation to Mission substation. Specifically, in 2004, the CPUC issued a Certificate of Public Convenience and Necessity to SDG&E to construct the project. The project was intended to alleviate congestion on the Southwest Powerlink that was brought about by the development of new generation that was constructed and selling power to the California Department of Water Resources. This project was estimated to take 24 months to construct. SDG&E projected, however, that during that two-year construction period, it would incur approximately $50M in congestion related costs per year that the line could avoid. SDG&E identified a construction workaround permitting it to temporarily operate one of its 69kV circuits at 230kV until the new line could be constructed and energized. The implementation of this workaround ultimately saved over $100M in congestion related costs. The operation of the formulaic rate mechanism provided SDDG&E prompt rate relief for this non-budgeted capital investment so that SDG&E could realize over $100M in net benefits for its customers.

Another example of operational flexibility is related to a project identified by SDG&E's Electric Grid Operations that would allow the system serving the southern Orange County area to operate reliably through the 2012 peak load season. The 138 kV Pico Loop-In project was identified in early 2012 as necessary to prevent involuntary load shedding to mitigate post-contingency thermal overloads in the 138 kV system serving south Orange County. Due to the project's short lead time it was not considered a typical planning project, and was not vetted through the CAISO's typical stakeholder process, although it was submitted to the CAISO as an Information Only project.

However, as the project fell within Cycle 6 and the CPUC engineering audit window it was reviewed and approved by the CPUC for need and cost-effectiveness and included in the Cycle 6 Forecast Period. The ability of SDG&E to recover the project costs through the formula rates while at the same time providing ratepayer protection by reflecting this in the Cycle 6 Forecast Period allowed SDG&E to do what was necessary to upgrade the system to meet reliability needs. In summary, SDG&E did not hesitate to accelerate any of these projects because SDG&E knew the project(s) would enhance customer transmission reliability with the knowledge that the Formula would fairly compensate SDG&E by allowing these costs to be included in its cost of service.

In addition, the CAISO can direct SDG&E to undertake investments that are intended to benefit the State as a whole and because the Formula provides prompt rate recovery, SDG&E is able to comply without the need to wait for subsequent rate recovery. The Formula also facilitates other State mandates like Renewable Portfolio Standards (RPS). To reach state RPS goals many Large Generator Interconnection Agreements (LGIAs) require network upgrades that the Formula recovers which enables SDG&E to proceed as quickly as possible.

Finally, the Formula promotes decoupling, which is another significant benefit to customers. More specifically, the decoupling of rate recovery from fixed periodic rate cases allows SDG&E to implement timely transmission solutions to ensure its customers receive a high degree of reliability. In fact, SDG&E has been recognized nationally for providing exceptional reliability and has received the prestigious Reliability One Award for providing the highest degree of reliability in the western United States for the past 7 consecutive years. Without the Formula, most transmission projects would have an extra regulatory delay built into their schedule to allow the proper costs to be determined, included in a rate case and receive approval. The delay would postpone customer congestion savings, reliability fixes, generation interconnections and meeting State goals.

3. TU Adjustment Report provides formula transparency

Q19. In the past, SDG&E as part of its TO3 formula process has included in its filing a TU Adjustment Report that provides a variance analysis between its TU Period cost of service versus recorded revenues, which in reality reflects historical costs from past cyclical filings. Will SDG&E continue to provide this report in TO4 to reflect additional formula transparency?

A19. Yes. As explained in more detail in the testimony of Mr. Lucero, SDG&E will continue to provide this report.

Q20. Why is it important to develop and file a TU Adjustment Report?

A20. In addition to providing for more transparency, the TU Adjustment Report is very useful to explain why SDG&E's costs are changing over time and thus provides customers with a greater understanding of why SDG&E's costs are changing. These costs include transmission operation and maintenance, A&G expenses, transmission plant, transmission depreciation expense and other costs that support transmission services.

4. Large Transmission Project Summary Report provides transmission project benefits and cost summary

Q21. Since the inception of its formula process SDG&E has provided third parties with an exhibit that describes each transmission project with a cost greater than $5 million dollars. This report describes each project's total cost along with how the project benefits customers. Will this report continue to be provided in TO4?

A21. Yes. From SDG&E's perspective it is very important customers understand the cost of projects and how these projects will benefit them.

5. The Posting of the Informational Filing Two Months Prior to its Filing Promotes Transparency by Providing Interested Parties a Pre-Filing Opportunity to Review

Q22. The TO3 Formula provides for a two-month review period prior to its filing. Does SDG&E propose to continue that practice under the TO4 Formula?

A22. Yes. Another positive attribute of the current formula process is that two months prior to filing the formula rates with the Commission, either June 15 for Cycles 1 and 2 or October 15 for subsequent cycles, is that SDG&E posts on its internet website a Draft Informational Filing that it files with the Commission on August 15 for Cycles 1 and 2 and December 15 for subsequent cycles. This posting provides several advantages.

- First, it allows SDG&E to work with the CPUC staff and other parties so that they can thoroughly understand the formula cost input and the resultant rates and their effects on customers.
- Second, it allows all parties to ask questions at technical conferences or in individual discussions about need and justification, cost inputs and questions related to transmission projects that appear in the forecast period.
- Third, it allows SDG&E to review with all parties the benefits of the major transmission projects included in the Forecast Period.

Q23. Does the two-month review provide any other benefits?

A23. Yes. It allows SDG&E to update the costs and in service dates of any transmission projects that appear in the forecast period.

Q24. Has SDG&E taken advantage of this last benefit?

A24. Yes. As explained above, in TO3 Cycle 6 during the 2 month review period SDG&E was able to update its estimated costs of the Sunrise project to actual costs, thus not having to true up these forecast costs at a later time period.

B. Other Specific Benefits of the TO4 Formula

1. Formula Assists SDG&E in Meeting Future Transmission Investment Challenges

Q25. What benefit does the formula provide to SDG&E as an investor owned utility?

A25. SDG&E's ultimate goal is to maintain a high degree of reliability for its customers, and it is in the best interest of those customers for SDG&E to be financially stable. A predictable revenue stream allows the Company to finance and manage its infrastructure development needs on a timely basis to respond to customer demands. Deriving rates on the basis of a formula instead of a Period 1 and Period 2 type filing achieves these goals.

Finally, the formulaic approach provides a continuous and steady stream of cash flow and earnings that encourages shareholder reinvestment combined with other sources of financing to expand the transmission system. Financial stability is necessary to maintain solid credit ratings to attract other sources of capital at favorable rates. SDG&E has recently issued long term debt at a low coupon rate as a result of its solid credit rating.

Indeed, the Commission has itself acknowledged the benefits of formulas in the context of Order No. 679, as discussed in A28 below.

Q26. Please explain challenges SDG&E faces with respect to making capital investments in transmission.

A26. There are several challenges that SDG&E faces when making decisions as to where to invest capital. Ms. Hrna speaks to the broader issues of attracting capital, but I note the following. First, in 1998, SDG&E turned over the operational control of its transmission grid to the CAISO. While this has provided significant consumer benefits, as I describe below, SDG&E no longer has the unilateral ability to make decisions regarding the operation, maintenance, and expansion of its transmission facilities. Decisions now involve the CAISO. The injection of a second party into the decision-making process, however well-intended, necessarily increases business risks associated with SDG&E's transmission assets and these business risks need to be appropriately compensated.

These business risks come in the form of SDG&E's transmission investment decisions that are now subject to review through the CAISO's transmission planning process. Further, SDG&E must comply with CAISO-mandated investments to benefit the State. SDG&E also must invest in network transmission upgrades mandated by FERC policy to facilitate LGIAs. In response to congestion in the San Diego area that was the result of market participants' use of SDG&E's transmission infrastructure, SDG&E has invested tens of millions of dollars in congestion-mitigation projects. Examples of projects that have reduced congestion costs to ratepayers include the second Mission-Miguel 230 kV line, discussed above, a second 500/230 kV transformer at Miguel substation, the 138 kV Encina Reliability Enhancement project which improved the deliverability of the 138 kV-connected generation at the Encina steam plant, and other similar projects. SDG&E has also sponsored projects to reduce forecasted congestion due to renewable integration (such as Sunrise), and is currently requesting approval from the CAISO and CPUC for approval to build at least two projects that will directly impact ratepayer costs due to congestion (specifically the Fanita Junction 138 kV project and the upgrade of the Sycamore Canyon-Chicarita 138 kV line). SDG&E had to obtain the approval of the CAISO to invest tens of millions of dollars in new transmission to save retail consumers hundreds of millions of dollars in congestion-related commodity costs.

As a result of California's failed experiment in deregulation, in January 2003 the CPUC placed SDG&E back in the role of securing capacity and energy to serve its customer needs. Since that time SDG&E has committed roughly $600 million to build new utility-owned generation facilities and it has procured an additional 740 MW of new gas fired generation in its service territory. All of this investment has been made pursuant to a competitive solicitation process and pursuant to CPUC orders. An additional 445 MW of new gas-fired generation via power purchase agreements is in process. All inclusive, SDG&E's portfolio provides 2953 MW of conventional generation and 2714 MW of renewable generation through purchase power agreements and/or utility-owned generation. As described later in this testimony, cost-effective access to this new generation requires substantial transmission capital investments and CAISO approval.

SDG&E also must invest to facilitate new market entrants where the entrants cannot finance on their own. Moreover, there is increased pressure to pay more and more for environmental mitigation ordered by regulatory agencies which in turn requires more capital.

The southern California utilities are facing the potential retirement of thousands megawatts of coastal Once-Through Cooling generation over the next decade, including the potential early retirement of 2,246 MW of nuclear generation at San Onofre due to technical issues within the plant. This could trigger hundreds of millions of dollars of generation and or transmission projects in San Diego and Orange Counties in order to replace generation resources and maintain transmission reliability. CAISO approval of these investments will also be necessary.

Q27. What other benefit does the formula process provide the company as well as its customers?

A27. The Formula removes disincentives to delay investments until cumbersome annual Period 1 and 2 filings could be made. Such filings would be burdensome and costly for SDG&E, interveners and the CPUC and FERC staffs to resolve. Also, it avoids the pancaking annual Period 1 and Period 2 filings, which in turn creates financial uncertainty due to a protracted period of time to litigate each filing.

VI. THE COMMISSION SUPPORTS TRANSMISSION FORMULAS

Q28. Has FERC indicated support for the use of transmission formulas?

A28. Yes. In Order No. 679 (Paragraph 386) the Commission states:

> We agree with several commenters that formula rates can provide the certainty of recovery that is conducive to large transmission expansion programs. Moreover, formula rates alleviate the need for other relief sought by commenters. For example, public utilities with formula rates will generally be able to flow through increased transmission investment without concern as to the Commission's five-month suspension policy with the exception of the suspension period for approval of initial rates. While we continue to encourage public utilities to explore the benefits of

> filing transmission-related formula rates, we will not require public utilities to use formula rates to recover incentives.

For these reasons and because SDG&E currently has a significant transmission expansion program, SDG&E concurs with the Commission that SDG&E's current and proposed formula process greatly assists in providing certainty of cost recovery that serves to provide an incentive to continue to invest in transmission to meet the growing needs of our customers.

Q29. What other benefits does the Formula provide?

A29. The Formula helps to remove any disincentive on the part of a utility to participate in energy efficiency demand response programs and other distributed generation projects because it removes volume through-put as a link to return on equity. This is because even though SDG&E's forecast energy sales for designing rates might be slightly off from actual sales, the true up provision of the formula allows for recovery of only actual costs.

VII. RATIONALE FOR THE INDEFINITE TERM OF THE TO4 FORMULA

Q30. Is SDG&E proposing its TO4 formula to be a specific length?

A30. No. SDG&E is proposing an indefinite time period for the duration of its TO4 formula.

Q31. Why is SDG&E asking for an indefinite timeframe for the duration of the TO4 formula?

A31. During a period of heavy transmission construction SDG&E has found that the annual formula filing provides the company with some regulatory certainty that funds will be available to compensate the company for the need to expand its transmission system to ensure that customers are provided with quality electric service. A formula without a termination date adds to certainty that SDG&E will be able to recover its costs related to an expanding transmission grid. The indefinite time also allows SDG&E the flexibility to identify and seek approval for significant long term transmission system upgrades through the CAISO stakeholder review process as well as seeking the recovery of these facility costs with certainty. The indefinite term also protects customers in an economy downturn.

VIII. TO4 FORMULA EQUATIONS WILL PERMIT SDG&E TO INCORPORATE APPROVED INCENTIVES

Q32. Mr. Avery, please discuss in broad terms the Order No. 679 incentive equations SDG&E proposes for the TO4 formula.

A32. In TO4, SDG&E is proposing to include the following incentive equations in its Appendix VIII formula:

- Incentive ROE
- 100% of Construction Work in Progress in rate base
- 100% recovery of Abandoned Project Costs

In order for SDG&E to implement its requested incentive(s), SDG&E will file for and receive Commission approval for project-specific incentives. Once the incentive is approved, SDG&E will then incorporate the incentive(s) into the Applicable TO4 cycle filing. Ms. Leonor Sanchez discusses the incentive provisions of Appendix VIII in her testimony (Exhibit SDG-3).

Q33. As part of your TO4 filing are you proposing the incentive ROE adder that is used for incentive projects during the length of the TO4 formula remain at some fixed value.

A33. No. SDG&E is retaining its rights to request the appropriate incentive ROE adder on a project-specific basis when it files the applicable Section 205 filing for incentive treatment.

IX. RATIONALE FOR CONTINUING TO RECEIVE THE 50 BASIS POINT ADDER FOR CAISO PARTICIPATION

Q34. Why is SDG&E requesting a 50 basis points ROE adder for continuing to participate in the CAISO?

A34. The 50 basis-points adder is appropriate for several reasons. First, the Commission granted this 50 basis-point adder to SDG&E in its TO3 Formula and there have been no changed circumstances warranting elimination of that adder. SDG&E continues to be a Participating Transmission Owner (PTO) under the CAISO tariff and the benefits that the Commission ascribes to such participation, as set forth in Order No. 679, are as applicable for TO 4 as they were for TO3. Second and more significantly, the

Commission has already granted requests for a 50-basis point adder for remaining a member of a regional transmission organization, noting[1]

> First, as we stated in Order No. 679-A, we will authorize incentive-based rate treatment for public utilities that continue to be a member of an RTO.
>
> Section 219 of the FPA specifically provides that the Commission shall provide for incentives to each transmitting utility that joins a Transmission Organization. The consumer benefits, including reliable grid operation, provided by such organizations are well documented and consistent with the purpose of section 219. The best way to ensure these benefits is to provide member utilities of an RTO with incentives for joining and remaining a member. As explained in Order No. 679-A, the decision to provide incentives for participation in an RTO is a policy one, aimed at promoting particular policy objectives, unrelated to any particular project….We further note that the level of the requested incentive, 50-basis points, is the same as that approved for similar utilities.

Those reasons apply equally to SDG&E. SDG&E's continued participation in the CAISO reaps benefits for consumers and the requested incentive is the same as that approved for similar utilities.

Q35. Please summarize some of the benefits arising from SDG&E's PTO status.

A35. Under the operational control of the CAISO, SDG&E's transmission assets are available for use by all market participants on a non-discriminatory, open-access, basis. The CAISO's open-access market protocols allow grid use to be optimized in accordance with market participants' commercial interests (expressed through price/quantity bids) and actual physical power flows. Prior to 1998, third-party access to SDG&E's transmission grid was governed by contract-path concepts which are not based on actual physical power flows and therefore did not allow for optimum grid use. While there have been ups-and-downs over time as the CAISO fine-tuned its market mechanisms, the overall result of turning operation control of SDG&E's transmission grid over to the CAISO has been a reduction in commodity costs paid by consumers throughout the CAISO Balancing Authority.

Q36. Are there other benefits SDG&E brings to the CAISO?

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1 *Baltimore Gas & Electric Company*, 120 F.E.R.C. ¶61,084, 60-61 (2007) (P 31).

A36. Yes. Because market participants use hourly price/quantity offers and bids to obtain access to SDG&E's transmission facilities they are not subject to contract-path based wheeling charges, market participants do not have to pay wheeling charges. Outside the CAISO (and prior to 1998 on the SDG&E's transmission system), wheeling charges are used to determine which entities are allowed access to the transmission system. Absent SDG&E being a CAISO PTO, market participants would have to pay SDG&E a wheeling charge. Such wheeling charges are an obstacle to efficient power markets because they are tied to contract paths, not actual grid physics.

As a PTO, SDG&E and the CAISO work together, along with Southern California Edison, Pacific Gas and Electric, and other PTOs located in California, to plan major transmission facilities. This coordinated planning process provides economic benefits to all CAISO consumers. Further, as a CAISO market participant, SDG&E provides supply resources that help to control commodity costs for all CAISO customers. SDG&E's participation adds to the CAISO's ability to provide a competitive energy market in California.

X. SDG&E'S PROPOSED ROE

Q37. SDG&E is proposing in this case a base ROE of 11.3%, comprised of a 10.3% cost of equity capital, plus a 50 basis points for business risk and 50 basis points for continued participation in the CAISO.

A37. Yes. The transmission risks, investment risks and general market risks that I have outlined above and that other witnesses outline in their testimony clearly demonstrate that SDG&E operates in a significantly risky environment warranting a ROE in the high end of the zone of reasonableness.

Q38. Once the Commission approves the Base ROE and the CAISO adder will SDG&E continue to use these elements in future filings?

A38. Yes, SDG&E proposes to continue using these amounts in all future filings during the period TO4 is in effect. Additionally, when SDG&E files for incentive treatment for specific projects in the future, as provided for in Order 679, SDG&E will file for the appropriate incentive ROE based on the project-specific risks.

XI. DIRECT ASSIGNMENT OF SPECIFIC TYPES OF COSTS RECORDED IN ACCOUNTS 920 THROUGH 935

Q39. Mr. Avery, you mentioned earlier in your testimony that SDG&E is proposing an option in this TO4 Formula to bifurcate expenses recorded in the referenced accounts to permit it to (1) directly assign certain specified types of events or occurrences to its transmission function and (2) allocate all other costs/expenses that do not lend themselves to direct assignment on the basis of labor ratios. Why is SDG&E proposing this direct assignment option?

A39. To be clear, SDG&E recognizes that there are two longstanding policies at issue with its proposal--cost causation and the Commission's policy preference for labor ratios to allocate A&G expenses. SDG&E is not discounting the Commission's policy preference for labor-based allocation of A&G expenses; however, SDG&E is proposing to carve out specific instances where the nexus between cost incurrence and cost responsibility is so clear that causation cannot be questioned and direct assignment would result in just and reasonable rates while a labor-based allocation method would not. The Commission has long recognized this tension between direct assignment and labor-based allocation, noting that "a utility may use some basis for functionalization other than labor ratios only if it can show the labor ratios are unreasonable in its situation (not merely that its proposed alternative method is reasonable)."[2] SDG&E's proposal is intended to apply only to those situations where: (i) direct assignment is consistent with cost causation principles, (ii) the relationship between cost incurrence and cost responsibility is obvious and reviewable and (iii) direct assignment is reasonable and cost allocation is unreasonable, *e.g.*, it would be patently unreasonable to use a labor ratio to allocate the balance to both distribution and transmission functions where the costs at issue have been affirmatively linked to the transmission function only.[3]

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[2] *Central Illinois Light Company (CILCO)*, 98 FERC ¶61, 242 at p. 61, 986 (2002), citing *Montana Power Company*, 83 FERC ¶ 61,211, at p. 61,235 n. 14 (1998). CILCO, at n. 21, explained the labor based allocation method as follows:

> Under the labor allocation method, General and Common plant costs and A&G expenses are "functionalized," or segregated into categories according to a utility's major operating functions. Such functions include production, transmission, distribution, customer accounts, customer service, information, and sales. This functionalization is in proportion to the ratio of the labor cost in each major function to total labor costs, less General and Common plant labor and A&G expenses.

[3] *Kern River Gas Transmission Co*., 117 FERC ¶61,077 (2006) at P.290.

Q40. Please discuss the type of situation you have in mind that would involve "clear causation" or a clear nexus between cost incurrence and cost recovery to qualify for direct assignment under SDG&E's proposal.

A40. The type of situation I have in mind is one in which an event would occur that would be directly attributable to transmission facilities. Distribution facilities would not be implicated or affected at all. If SDG&E were to use a labor-ratio allocator in that situation, approximately 85% of the costs of the event would be allocated to the distribution function, despite the fact that the costs would be directly and uniquely linked to the operation of the high-voltage transmission grid. This would be contrary to the "*fundamental* theory of Commission ratemaking which is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred."[4] A labor allocation ratio may be appropriate for allocating many types of A&G costs across all affected business units, but not in the circumstance of a major cost linked directly to transmission operations.

Q41. As a practical matter, how would SDG&E implement its proposal?

A41. SDG&E is proposing that where (1) costs or expenses recorded to the relevant account are related to an identifiable, significant event and (2) the event pertains solely to the transmission function, as opposed to the distribution function, SDG&E should be permitted to directly assign those costs to its transmission function. All other costs recorded to the A&G accounts that do not lend themselves to direct assignment would be allocated on the basis of labor ratios to all of SDG&E's functions. Ms. Somerville will discuss the accounting aspects of SDG&E's ratemaking proposal in greater detail in her testimony (Exhibit No. SDG-5).

Q42. Why is SDG&E proposing an option in its TO4 Formula to permit direct assignment in specified circumstances?

A42. The TO3 Formula did not include an express provision permitting SDG&E to directly assign costs consistent with cost causation principles. It only expressly provided for allocation. The TO4 Formula rectifies that omission by permitting direct assignment

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4 *Northern States Power Co.*, Opinion 383, 64 FERC ¶61,324 a p. 63,379 (1993), *reh'g denied* 74 FERC ¶61,106 (1996) (emphasis in original).

under limited circumstances, *i.e.*, where direct assignment is consistent with cost causation principles and labor-based allocation is not.

XII. CONCLUSION

Q43. Does this conclude your testimony?

A43. Yes, it does.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

James P. Avery, being duly sworn, on oath, says that he is the James P. Avery identified in the foregoing prepared direct testimony; that he prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

James P. Avery

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, Rosalinda Rossi, a Notary Public, personally appeared James P. Avery, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ROSALINDA ROSSI
COMM. #1858772
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jul 24, 2013
LS01

Rosalinda Rossi

Exhibit No. SDG-2

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
ED LUCERO
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-2

#275002

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PREPARED DIRECT TESTIMONY OF
ED LUCERO
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name, position and place of employment.

A1. My name is Ed Lucero, and I am Manager of Transmission Revenues and Budgets for San Diego Gas & Electric Company (SDG&E). My business address is 8315 Century Park Court Bldg. 2, San Diego, CA 92123.

Q2. Please summarize your higher education.

A2. I hold a Bachelor's Degree in Mechanical Engineering from Texas A&M University and Master of Business Administration degree with a finance concentration from the University of Texas at EI Paso.

Q3. Please describe your current responsibilities as well as prior experience before coming to SDG&E.

A3. My current responsibilities include providing analytical support to the company for Federal Energy Regulatory Commission (Commission or FERC) matters regarding electric revenue requirements, cost of service, rate design and California Independent System Operator (CAISO) matters. From 1972 to 1986, I worked for El Paso Electric Company (EPEC) as a Power Plant Engineer, System Planner, and subsequently as Rate Manager. As Rate Manager I supervised numerous costs of service and rate design filings before the FERC, Texas Public Utility Commission and the New Mexico Public Service Commission. After leaving EPEC, I worked for two years as a consultant with EBASCO Consulting and then 11 years for Price Waterhouse (PW) as a Manager in the

Public Utilities Division. During my period as a consultant, I worked for numerous investor-owned utilities, municipalities and industrial customers (PW audit clients) throughout the country, specializing in electric matters including the derivation of electric revenue requirements, cost of service studies and retail and wholesale rate design.

During my career, I have testified before a number of state commissions, city councils, and the FERC. I am co-author of the *National Association of Regulatory Utility Commissioners Electric Cost Allocation Manual* that was published in January 1992 *(Manual).* This *Manual* is used by numerous investor-owned electric utilities and municipalities throughout the country as a guide for doing electric cost of service studies.

At SDG&E, I have worked on various electric restructuring issues specializing in transmission and operational issues related to the CAISO, supervised filings with FERC concerning transmission rates, pass through of Reliability Must Run costs, Special Transmission Surcharges, SDG&E's Transmission Revenue Balancing Account (TRBAA), and the CAISO Transmission Access Charge (TAC).

II. PURPOSE OF TESTIMONY

Q4. What is the purpose and organization of your testimony?

A4. The purpose and organization of my testimony is as follows:

I. Introduction
II. Purpose of Testimony
III. Organization of Filing
IV. Key Differences between the TO3 Formula and the TO4 Formula
V. Description of TO4 Formula and Cycle[1] Timelines
VI. New Transmission Depreciation Rates
VII. *Pro Forma* Cost Allocation Adjustments Made to Cycle 1 Recorded Base Period
VIII. *Pro Forma* Cost Adjustments Made to Cycle 1 Recorded Base Period
IX. Final TO4 True-Up Period Adjustment
X. Refunds Under TO4 Formula
XI. Retail Rate Design

[1] The term, "cycle" refers to the specific annual filing under the Formula. For instance, Cycle 1 will be the first annual filing under the TO4 Formula.

III. ORGANIZATION OF FILING

Q5. Please briefly explain the organization and the information in the various volumes of the TO4 Filing.

A5. There are 5 volumes in this Filing and provides detail as to what information is contained in each volume. In general, the volumes contain the following:

- Volume 1 contains: the cover letter to the Filing and a redlined and clean version of the proposed changes to the currently-effective Appendix VIII to reflect the proposed TO4 Appendix VIII;
- Volumes 2 and 3 contain the testimony supporting the TO4 Formula;
- Volume 4 contains the TO4 Base Period cost of service cost statements which include a Statement BK-1 and BK-2 that develops Base Transmission Revenue Requirements (BTRR) for End Use Customers (retail customers) and CAISO Wholesale Customers, respectively. Additionally Volume 4 contains Statement BL setting forth applicable retail rate design and CAISO High and Low Voltage Transmission Revenue Requirements (TRR);
- Volume 5 contains all the work papers supporting Volume 4.

IV. KEY DIFFERENCES BETWEEN THE TO3 FORMULA AND THE TO4 FORMULA

Q6. Please explain the key differences between the TO3 Formula and the TO4 Formula.

A6. Leonor Sanchez will discuss those changes in great detail; however, I note that because the TO3 Formula has worked well and parties are familiar with the Formula process, SDG&E has attempted to limit changes to the TO4 Formula to the maximum extent practicable.

Q7. Please outline the key differences.

A7. The key differences are as follows:

1. **TU Period and Base Period will be the same calendar year** – in the TO4 Formula the TU Period and the Base Period will be the same calendar year. In TO3, the Base Period was a calendar year and the 12-month TU Period ended 3 months later. Thus, there was only a 9 month overlap between the Base Period and TU Period. These two different costs of service periods (Base Period and TU Period) required SDG&E to prepare two sets of cost data statements, Statements AD through BL. In TO4, using

the same calendar for both the Base Period and TU Period will allow SDG&E to prepare only one set of cost statements, AD through BL, which will save a considerable amount of time in the preparation of the formula filing as well as making it much easier for third parties to review the annual cyclical filings. The specific dates for the beginning cycles of the TO4 Tariff are explained in more detail in the following section.

2. **One TU Period Adjustment for both Retail and CAISO Wholesale** – in TO3 SDG&E essentially had developed two TU Adjustment processes; one for retail and one for CAISO Wholesale customers. The Retail TU Adjustment was the difference between recorded revenues and the TU Cost of Service. Retail recorded revenues, is readily available from SDG&E's books so information to develop the retail TU Adjustment is readily available. On the other hand, information to calculate the ISO TU Adjustment is not readily available and a rather complicated and cumbersome process was needed in TO3 to calculate a proxy for the CAISO transmission recorded revenues. This was accomplished by looking at past cyclical TO3 TU costs of services, designing retail rates at the transmission level to reflect these costs of services and then applying the resulting rates for these costs of services to the TU Period billing determinants to reflect CAISO Wholesale TU recorded revenues. Although this process produced correct results, SDG&E's new TO4 process greatly simplifies the process.

   Thus, in TO4, SDG&E uses the Retail TU Adjustments for the CAISO Wholesale TU Adjustment. Raulin Farinas discusses this issue in more detail in his testimony (Exhibit No. SDG-6).

3. **Flexibility to Include Project-Specific Ratemaking** – FERC policy, as expressed in Order No. 679 and subsequent orders, provides for special ratemaking incentives for transmission projects that meet specified criteria. The TO3 Formula did not contain any mechanism by which such project-specific rates could be incorporated, due in part to a provision of the TO3 Settlement that precluded SDG&E from seeking any incentives under Order 679 during the term of the TO3 Formula. Going forward, SDG&E believes it important to have flexibility to include project-specific incentive

rates as part of its overall TO Tariff. TO4 Appendix VIII include provisions that will allow the formula to account for:

- ROE incentive adder for particular projects;
- 100% recovery of CWIP in rate base;
- 100% recovery of abandoned project costs

Utilization of any of the above incentives would only occur following Commission approval of rate incentives for a particular project. If and when the Commission approves the requested incentive(s), SDG&E will reflect the approved rate treatment in the Applicable TO4 cycle filing. Leonor Sanchez discusses the incentive provision(s) set forth in Appendix VIII in more detail in her testimony.

4. **Allocation of Electric Intangible Plant –** another modification pertains to SDG&E's allocation of electric intangible plant. In TO3, SDG&E allocated electric intangible plant using its Transmission Wages and Labor Allocation Factor, more commonly referred to as the transmission labor ratio. In TO4, SDG&E is proposing a bifurcated approach that permits it to either allocate this expense using a labor ratio or to directly assign it consistent with the methodology used for distribution at the CPUC and with cost causation principles. Michelle Somerville also discusses this issue in her testimony.
5. **Direct Assignment of Unique A&G Expenses Tied Directly to the Transmission Function**–Michelle Somerville explains that while it may be reasonable to use a labor ratio to allocate many types of A&G costs across functions, for certain A&G costs that are directly and uniquely tied to transmission, use of a labor allocator across all functions would produce unreasonable results and direct assignment to the transmission function would produce reasonable results. SDG&E therefore proposes to segment costs recorded to the AG&E accounts and directly assign A&G costs that are directly and uniquely tied to the transmission function to transmission and to use a labor allocator across all functions for all other A&G costs booked to those A&G accounts.
6. **Miscellaneous Modifications**—SDG&E Witness Leonor Sanchez discusses other modifications.

V. DESCRIPTION OF TO4 FORMULA AND CYCLE TIMELINES

A. Description of Formula and Cycle Timelines

Q8. Please explain SDG&E's TO4 Formula and related cycle timelines and how they differ from TO3.

A8. The TO4 Formula is similar to SDG&E's TO3 Formula with the few exceptions explained below. I have prepared Exhibit No. SDG-2-3 to show a timeline for the first few cycles of TO4, including the applicable components of each cycle. Basically, the components for each cycle will include the following

1. Base Period
2. Forecast Period
3. TU Adjustment
4. Interest TU Adjustment
5. Rate Effective Period (REP)

The following components are applicable to each TO4 cycle.

- **TO4 Cycle 1 is shown in Part A**
  1. a recorded Base Period of 12-months ended May 31, 2012
  2. a 27- month Forecast Period of June 2012 through August 2014, and
  3. a 12- month REP from September 1, 2013 through August 31, 2014
- **TO 4 Cycle 2 is shown in Part B**
  1. Base Period will use a recorded 2013 calendar year
  2. Forecast Period will be a 24-month period from January 2014 through August 2015
  3. TU Period Adjustment will be a 4-month period of September 2013 through December 2013 and
  4. Interest TU Adjustment applicable to Cycle 2 TU Adjustment balance
  5. The 12-month REP from September 1, 2014 through August 31, 2015 shall be extended for another four months through December 31, 2015 to provide for the transition to a calendar year REP for Cycle 3 and subsequent cycles, as described below.
- **TO4 Cycle 3 is shown in Part C**
  1. Base Period will be a recorded 2014 calendar year

2. Forecast Period will be a 24-month period of January 2016 through December 31, 2016
3. TU Period Adjustment will be a 2014 calendar year
4. Interest TU Adjustment applicable to Cycle 3 TU Adjustment balance
5. REP will be 12-months from January 1, 2016 through December 31, 2016

After Cycle 3, all successive cycles will be similar to Cycle 3 with regards to timing and the length of the Base Period, Forecast Period, TU Period, and Rate Effective Period.

B. Change in Rate Effective Period and Forecast Period

Q9. Based upon the above, why are the BTRR rates in Cycle 2 extended to December 31, 2015, which is four months beyond the normal 12-month REP?

A9. The reason for this four-month extension is to permit SDG&E to transition to a point where it can commence billing all End Use rates, both for transmission and distribution on January 1 of each year. This conforms to SDG&E's current convention of billing all other transmission and CPUC regulated retail rates beginning on January 1. This change will be good for retail customers as all their rates will only change one time per year on January 1. Exhibit No. SDG-2-2 reflects this revised timeline for Cycle 2 and subsequent cycles.

Q10. You indicated above that SDG&E bills other transmission rates on January 1. What transmission rates are currently billed starting on January 1.

A10. Currently, SDG&E begins billing revised transmission rates on January 1, which include the Reliability Service, Transmission Revenue Balancing Account (TRBA), and the Transmission Access Charge Balancing Account Adjustment (TACBAA) rates.

Q11. Mr. Lucero for Cycle 2 will the Rate Effective Periods and Forecast Periods coincide?

A11. Yes. The last month of the Forecast Period needs to end on the last month of the REP. In this way, customers pay for the correct weighed transmission plant additions that are in the Forecast Period.

Q12. Will the last month of the REP also coincide with the last month of the Forecast Period for cycles subsequent to Cycle 2?

A12. Yes and this is shown in Exhibit No. SDG-2-2.

C. TO4 TU Adjustments

Q13. Why does Cycle 1 not contain a TU Adjustment Period?

A13. Cycle 1 does not contain a TU Adjustment Period because the first TU Adjustment month for TO4 does not begin until SDG&E has actual recorded revenues and costs for the Cycle 1 REP, beginning September 1, 2013. That said, SDG&E will not have these actual revenues and costs until it files Cycle 2.

Q14. Does Exhibit No. SDG-2-2 reflect this fact for Cycle 2?

A14. Yes, Exhibit No. SDG-2-2, line 26, shows that Cycle 2 will be filed August 2014 at which time SDG&E will have recorded revenues and costs for September 2013 through December 2013 (four months—line 28), which will be the first TU Period in TO4.

Q15. Why is the first TU Adjustment Period only 4 months long?

A15. The first TU Adjustment Period is only 4 months because this is the length of time necessary to start a normal 12-month TU Period beginning in Cycle 3. Exhibit No. SDG-2-2, line 37 shows that SDG&E begins using a normal 12-month TU Adjustment in Cycle 3.

D. Interest TU Adjustment

Q16. Why does the Interest TU Adjustment component of the TO4 Formula only begin in Cycle 2 and not Cycle 1?

A16. Since the Interest TU Adjustment is only applicable to the under recovered or over recovered balance of the TU Adjustment and since the first TU Adjustment balance does not occur until we have calculated the first TO4 TU Adjustment in Cycle 2, the first Interest TU Adjustment does not occur until Cycle 2.

Q17. How does the Interest TU Adjustment work?

A17. Raulin Farinas explains why the Interest TU Adjustment is needed and how it is calculated in his testimony.

E. Duration of TO4 Formula

Q18. Does the TO4 Formula have a pre-determined end date?

A18. No, the formula rate mechanism proposed for TO4 contains built-in flexibility to adjust as transmission operations change and new capital projects are developed. As such, there is no need to sunset the formula as of any particular date. While future conditions may necessitate changes in the formula, the need for those changes will be evaluated if and when they occur.

F. TO4 Cycle 1 Base Period End Date

Q19. Please explain why the TO4 Cycle 1 Base Period ends May 31, 2012 and the Forecast Period begins June 1, 2012 and ends August 2014?

A19. The Cycle 1 Base Period ends May 31, 2012 in order to smooth the rate impact of the Sunrise Powerlink Transmission Project (Sunrise). In its TO3 Cycle 6 Supplemental filing,[2] SDG&E reflected Sunrise in the Forecast Period. Sunrise's capital costs of slightly less than $1.8 billion were weighted 100% in the Forecast Period. By comparison, at the end of the Cycle 1 Base Period, May 31, 2012, SDG&E's transmission plant balance was equal to approximately $1.84B. The addition of Sunrise effectively doubled SDG&E's in-service transmission plant and had a significant effort on SDG&E's transmission revenue requirements.

In TO4 Cycle 1, had SDG&E's Base Period ended in June 2012 rather than May 2012, Sunrise weighting in the Base Period would have been only 1/12. This in turn would have drastically reduced revenues and created significant revenue volatility which we were able to avoid by using a Base Period ended May 2012 as discussed below.

Q20. Why is it advisable to avoid significant volatility in transmission revenues?

A20. One of SDG&E's primary aims in the recovery of costs is to ensure customers are charged a relative consistent revenue stream over time. That is, SDG&E tries to avoid having its customers see unnecessarily high variability in their bills**.** To the extent TO3 Cycle 6 included a 100% weighting of Sunrise in the forecast period, use of 100% weighting in the TO4 Cycle 1 Forecast Period contributes to a constant level of revenue recovery, along with the other items mentioned below.

Q21. Will the fact that Sunrise is being weighted 100% in the TO4 Cycle 1 Forecast Period adversely affect the transmission rate increase SDG&E's retail customers will experience when the Cycle 1 rates go into effect September 1, 2013?

A21. No. From a retail perspective, even though SDG&E in Cycle 1 is including Sunrise at a 100% weighting in the Forecast Period, the increased transmission revenue impact will be considerably mitigated by SDG&E's CAISO TACBAA rate that SDG&E filed in December 2012[3] for services applicable to 2013 and will file in December 2013 for

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[2] ER12-2454 filed File Oct 2, 2012

[3] On February 4, 2013, the Commission issued a Letter Order accepting the filing in Docket No. ER13-602-000.

services applicable to 2014. Pursuant to the CAISO's TAC mechanism, a Participating Transmission Owners (PTO) High Voltage Revenue is socialized among all other PTOs in the CAISO. As such, SDG&E's retail customers will pay only their CAISO load ratio share of the High Voltage projects or about 10% of its revenues. All other PTOs will pay their load ratio share of SDG&E's High Voltage projects, or about 90% of these costs.

G. Other Timing Aspects of TO4 Formula Cycles

Q22. What are some of the other key aspects of the TO4 Formula's cyclical timing?

A22. One aspect is that in Cycle 2, the formula will quickly transition to using FERC Form 1 information to populate the cost information needed by the formula as explained further below. This is explained more thoroughly in the testimony of Lolit Tanedo.

Q23. Is the inclusion of the Final TO3 TU Adjustment another important aspect of TO4?

A23. Yes. As shown on line 19 of Exhibit No. SDG-2-3, the TO4 formula incorporates a provision to include a Final TO3 TU Adjustment consistent with the TO3 Settlement Agreement.[4] This allows SDG&E to refund or collect any costs from customers for those months after the TO3 Cycle 6 TU Period, which ended March 2012. The Final TO3 TU Period months will be April 2012 through August 2013.

Q24. Is there another reason for using September 2013 as the first month of the Cycle 2 True-Up period?

A24. Yes. By using September 2013 as the first TU month in the TO4 formula, there is a continuous period of months that are trued up in going from TO3 to TO4. That is, the last TU Period month for TO3 is August 2013 and the first month TO4 TU Period month is September 2013.

VI. NEW TRANSMISSION DEPRECIATION RATES

Q25. SDG&E is requesting approval of new transmission depreciation rates to go into effect September 1, 2013. Please explain.

A25. Bob Wieczorek has filed testimony to support and request new transmission depreciation rates to go into effect September 1, 2013. That is the date on which SDG&E will begin recording these proposed depreciation rates.

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[4] *San Diego Gas & Electric Company*, 119 FERC ¶61,169 (2007).

Q26. Has SDG&E quantified the cost impact of its new proposed transmission depreciation rates?

A26. Yes. Mr. Wieczorek in his testimony quantifies on an annual basis the cost impact of the new proposed transmission depreciation rates by applying them to the plant balances of the last month of the Base Period, May 31, 2012, and comparing this figure to an amount calculated by taking the May 31, 2012 plant balances times the current depreciation rates.

Q27. Does Mr. Wieczorek show any other cost comparisons?

A27. Yes. In TO4 Mr. Wieczorek has developed an exhibit that shows a cost comparison of annual depreciation costs with and without Sunrise. First, as explained above, he determines the annual depreciation costs using current rates using May 31, 2012 plant balances. Second, Mr. Wieczorek then takes the May 31, 2012 transmission plant balances and adds in the Sunrise plant. Mr. Wieczorek then multiplies this total times the proposed new higher depreciation rates to yield new annual depreciation costs including Sunrise. This comparison shows the annual depreciation expense SDG&E will incur with Sunrise included in plant in service.

Q28. Does Mr. Wieczorek address any other topics related to depreciation?

A28. Yes. Mr. Wieczorek also discusses and quantifies the amount of removal costs SDG&E has recorded commencing July 1, 2007 consistent with the TO3 Settlement.

Q29. Are the new depreciation rates reflected in the Cycle 1 Base Period?

A29. No. SDG&E will not begin recording these rates until September 1, 2013, when the TO4 Formula becomes effective. Because the Cycle 1 Base Period is intended to reflect only recorded costs, SDG&E has chosen to reflect these new rates in its Cycle 2 True-Up Adjustment, when they are recorded beginning September 1, 2013.

VII. *PRO-FORMA* COST ALLOCATION ADJUSTMENTS MADE TO CYCLE 1 RECORDED BASE PERIOD

Q30. Has SDG&E made any pro forma cost allocation adjustments to its recorded Cycle 1 Base Period, 12-months ended May 2012?

A30. Yes. SDG&E has adjusted the Cycle 1 Base Period to reflect an allocation of common A&G and common plant to SDG&E's Electric Division on the basis of labor ratios. SDG&E has also directly assigned the appropriate portion of Intangible plant to transmission service, consistent with cost causation principles. Both adjustments are consistent with the methodology in SDG&E's pending rate cases before the CPUC.

VIII. *PRO-FORMA* COST ADJUSTMENTS MADE TO CYCLE 1 RECORDED BASE PERIOD

Q31. Has SDG&E made any *pro-forma* cost adjustments to recorded Base Period costs as part of its Cycle1 filing?

A31. Yes. Although SDG&E's normal TO4 formula practice will be to not make any adjustments to Base Period recorded expenses, the below adjustments are needed in Cycle 1 to implement TO4.

1. The first *pro forma* adjustment is required to reflect the Commission's Order in Docket No. ER11-4318-001 associated with SDG&E's TO3 Cycle 5 filing, directing SDG&E to remove capitalized wildfire insurance premiums and wildfire property damages to third parties recorded to transmission plant. Ms. Tanedo discusses the amounts of capitalized wildfire insurance premiums and third-party wildfire damages have been removed from the Base Period transmission plant as well as related adjustments that have been made to SDG&E's Electric Division Account 925, Injuries and Damages.
2. A second *pro forma* cost adjustment is related to the exclusion of wildfire damages paid to third parties that were recorded in the Base Period but were recovered in the TO3 Cycles 5 and 6 True-Up Period costs of services. These specific wildfire damages to third parties have also been removed because they are non recurring expense and will not appear again in the Cycle 1 Rate Effective Period. Removing these costs now also will ensure that customers are not overcharged in the Cycle 1 Rate Effective Period as these expenses are not applicable to the Base Period and will not be subject to a TO4 True-Up Adjustment.

IX. FINAL TO4 TU PERIOD ADJUSTMENT

Q32. Will the TO4 Formula require a Final TU Adjustment?

A32. The TO4 Formula will only require a Final TU Adjustment if the TO4 Formula terminates. SDG&E is not proposing a termination date of the TO4 Formula and will not speculate now on how a potential TO4 Final TU Adjustment would be implemented.

X. REFUNDS UNDER TO4 FORMULA

Q33. How will refunds under TO4 Formula be implemented?

A33. Refunds under TO4 will be implemented in the following manner for retail and CAISO wholesales refunds. CAISO wholesale refunds will be effectuated pursuant to the CAISO tariff. Retail refunds will be effectuated pursuant to the True-Up mechanism of the TO4 Formula.

XI. RETAIL RATE DESIGN

Q34. Is SDG&E changing its retail rate design in TO4 Cycle 1?

A34. No. It is using the same transmission retail rate design that it used in TO3 Cycle 6.

Q35. Does this conclude your testimony?

A35. Yes, it does.

Exhibit No. SDG-2-1

TO4 Testimony

B. Account 352-Structures and Improvements
   1. Subaccount E352.10 – Structures and Improvements – “Other” Transmission
   2. Subaccount E352.20 – Structures and Improvements – South West Powerlink – SWPL – Transmission
   3. Subaccount E352.60 – Structures and Improvements – Sunrise Powerlink – SRPL – Transmission

C. Account 353-Station Equipment
   1. Subaccount E353.10 – Station Equipment – “Other”
   2. Subaccount E353.20 – Station Equipment – SWPL
   3. Subaccount E353.40 – Station Equipment – Palomar
   4. Subaccount E353.60 – Station Equipment – SRPL

D. FERC Account 354-Towers and Fixtures
   1. Account E354.10 – Towers and Fixtures – Other
   2. Subaccount E354.20 – Towers and Fixtures – SWPL
   3. Subaccount E354.60 – Towers and Fixtures – SRPL – Sunrise

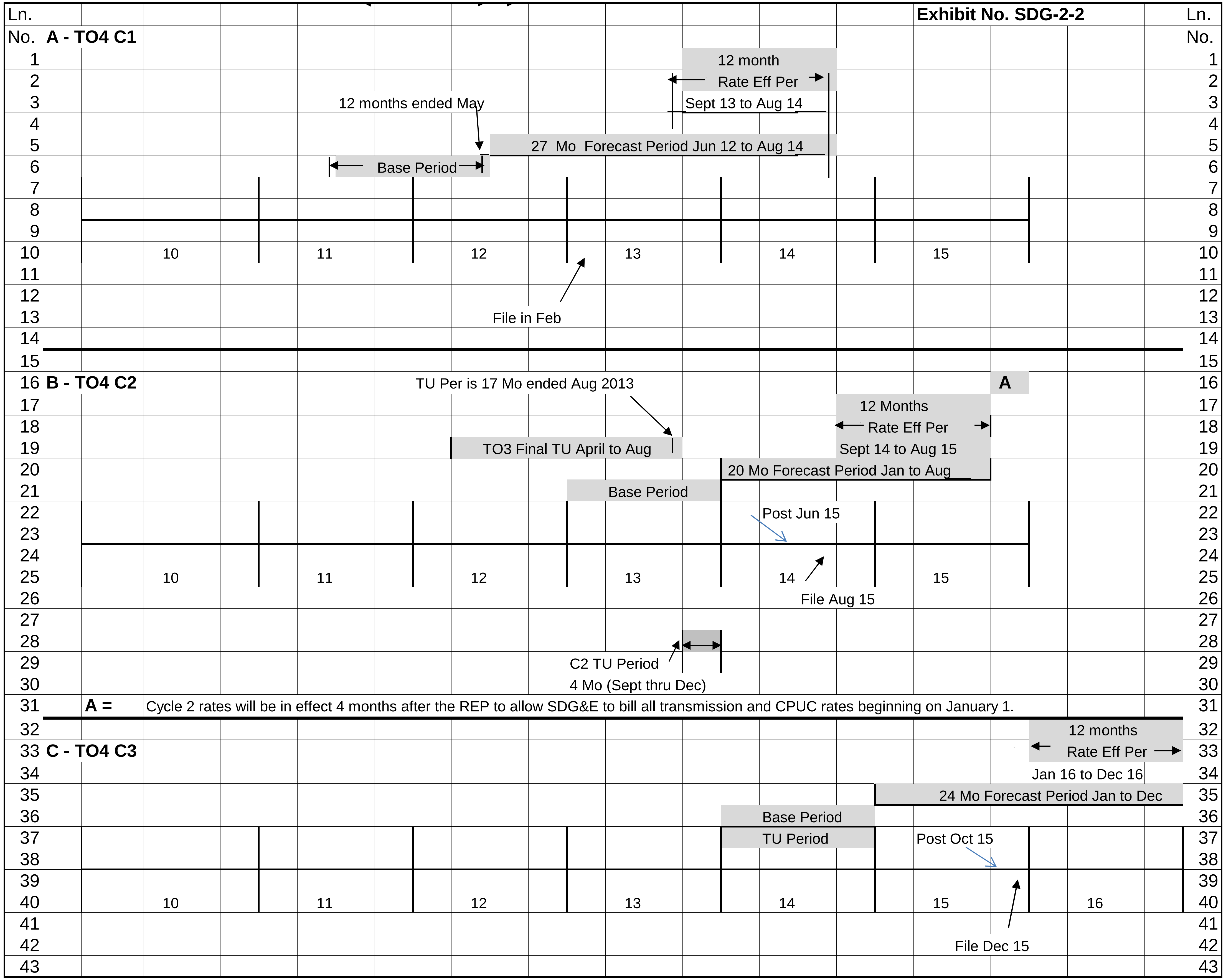
E. FERC Account 355-Poles and Fixtures
   1. Subaccount E355.10 – Poles and Fixtures – Other
   2. Subaccount E355.20 – Poles and Fixtures SWPL – Other
   3. Subaccount E355.60 – Poles and Fixtures – SRPL – Sunrise

F. Account 356-Overhead Conductors and Devices
   1. Subaccount E356.10 – Overhead Conductors and Devices – Other
   2. Subaccount E356.20 – Overhead Conductors and Devices – SWPL
   3. Subaccount E356.60 – Overhead Conductors and Devices – SRPL – Sunrise

G. Account 357-Underground Conduit and Cables
   1. Subaccount E357.00 – Transmission Underground Conduit – Other and SWPL
   2. Subaccount E357.60 – Transmission Underground Conduit – SRPL

H. FERC Account 358-Underground Conductors and Devices
   1. Subaccount E358.00 – Transmission Underground Conductors and

Exhibit No. SDG-2-2



VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Ed Lucero, being duly sworn, on oath, says that he is the Ed Lucero identified in the foregoing prepared direct testimony; that he has prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Ed Lucero

Ed Lucero

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 11th day of February, 2013 before me, ANNIE VICTORIA RUIZ, a Notary Public, personally appeared Ed Lucero, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Annie Victoria Ruiz

ANNIE VICTORIA RUIZ
COMM. #1877490
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2014
ST01

Exhibit No. SDG-3

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
LEONOR SANCHEZ
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-3

#274833

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UNITED STATES OF AMERICA
BEFORE THE
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San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF

LEONOR SANCHEZ

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name and business address?

A1. My name is Leonor Sanchez. My business address is 8315 Century Park Court – CP21G San Diego California, 92123-1548.

Q2. By whom are you employed and in what capacity?

A2. I am employed by San Diego Gas & Electric Company (SDG&E) as a Senior Business Analyst in the Transmission Revenue and Budgeting group. My responsibilities include assisting in developing and analyzing transmission revenue requirements.

Q3. Please briefly describe your educational and professional background.

A3. I received a Bachelor of Science in Business Administration with an emphasis in Accounting from California State University of San Marcos. I also attended National University where I completed all coursework required for a Master of Business Administration with an emphasis in Finance Management. I have been employed by SDG&E since November 2000 in various positions, and assumed the position of Senior Business Analyst in December 2007 in the Transmission Budgeting and Revenue Requirement group. In this position, I am involved with the overall determination of transmission revenue requirements and rate design for transmission rates.

Q4. Have you submitted testimony before the Federal Energy Regulatory Commission (Commission or FERC) in the past?

A4. Yes, in Docket No. ER12-1417-000 related to SDG&E's Appendix X Formula for calculating the allocated costs to Citizens Sunrise Border-East Line Rate Under SDG&E's Transmission Owner (TO) Tariff.

II. PURPOSE OF TESTIMONY

Q5. What is the purpose of your testimony?

A5. The purpose of my testimony is to sponsor SDG&E's TO4 Appendix VIII and to explain SDG&E's proposed modifications to its currently-effective TO3 Appendix VIII to derive an Appendix VIII for its TO4 Formula. Appendix VIII is located within SDG&E's TO Tariff. As explained below, the proposed modifications to the TO4 Appendix VIII are due to a number of reasons, including: incorporating specified incentives pursuant to Order No. 679 and making substantive and organization changes to facilitate use.

Q6. How is your testimony organized?

A6. My testimony is organized into the following sections:

I. Introduction
II. Purpose of Testimony
III. Overview of the Types of Changes
IV. Non-Substantive Changes
V. Substantive Changes

III. OVERVIEW OF THE TYPES OF CHANGES

Q7. Please explain the types of changes SDG&E is proposing to its TO3 Appendix VIII to develop its TO4 Appendix VIII.

A7. For convenience, I have prepared Exhibit No. SDG-3-1 which contains a redline version of SDG&E's currently effective TO3 Appendix VIII reflecting the changes SDG&E is proposing for itsTO4 Appendix VIII. I have grouped these changes into two categories—Non-Substantive, i.e., Non-Revenue Changes, and Substantive Changes.

1. Non-substantive Changes are highlighted in blue and pertain to clarifications, simplifications and reorganizations.
2. Substantive Changes are highlighted in **red** and pertain to, among other things, Order No. 679 Incentives, allocation methodology for total common plant to SDG&E's Electric Division; Administrative and General (A&G) Expense-

Electric Division (allocation and direct assignment)**;** Miscellaneous Intangible Plant (allocation and direct assignment) and Depreciation Rates.

IV. NON-SUBSTANTIVE CHANGES

Q8. Where do you provide a more detailed explanation of your non-substantive changes?

A8. I have prepared Exhibit SDG-3-2 that lists and explains all the clarifying and organizational changes in TO4 Appendix VIII. Column 1of this exhibit describes the revised or new term, column 2 shows the page number in Exhibit No. SDG-3-1 where the change occurs, column 3 indicates that no change to revenues occurs, and column 4 explains the basis for the change.

V. SUBSTANTIVE CHANGES

Q9. What types of substantive changes have been made to Appendix VIII and why were they made?

A9. The two types of substantive changes may be grouped into two broad categories: (1) Order No. 679 Transmission Incentives and (2) Other Miscellaneous Changes. I have prepared Exhibit SDG-3-3 which lists the substantive changes. Column 1 describes the new term or allocation factor, column 2 shows the page number in Exhibit No. SDG-3-1 where the change occurs, column 3 indicates that the change affects revenues and column 4 explains the rationale for the change.

More particularly, Order No.679 allows utilities to seek specified incentives for qualified projects that enhance transmission reliability and reduce congestion. SDG&E is modifying Appendix VIII to permit recovery of transmission incentives that the Commission may authorize for future transmission projects. Other Miscellaneous Substantive Changes include: allocation methodologies for common plant and intangible plant, direct assignment, updated Franchise Fees and Uncollectibles and revised True-Up Adjustment.

Q10. Which Order 679 incentives has SDG&E modified Appendix VIII to incorporate for future projects?

A10**.** The specific incentives reflected in Appendix VIII are set forth below, although SDG&E also reserves its right to seek additional incentives consistent with Order 679, as it may be amended from time to time.

- Incentive Return on Equity (ROE) adder for specifically approved projects or a transmission project using Advance Transmission Technology;
- 100% recovery of transmission construction work in progress (CWIP) in rate base and
- 100% recovery of abandoned project costs.

A. Order No. 679 Incentives and Statement BK-1

Q11. Please explain how SDG&E proposes to incorporate Order No. 679 incentives into Appendix VIII of TO4.

A11. Appendix VIII describes how the Base Transmission Revenue Requirements are derived for End-Use Retail Customers ($BTRR_{EU}$) and CAISO BTRR ($BTRR_{CAISO}$). I have revised Appendix VIII to incorporate changes to the Formula process associated with the recovery of an Incentive Return on Equity for specifically approved projects and Advance Transmission Technology, and 100% recovery of CWIP in rate base.

Q12. Please continue.

A12. To help better understand how Appendix VIII has been modified to include calculations for approved incentives, I have included for illustrative purposes the TO4 Cycle 1 Statement BK-1 as Exhibit SDG-3-4 to my testimony. Statement BK1 has been modeled to follow Appendix VIII to demonstrate how these changes will be incorporated in developing Total Base Transmission Revenue Requirements.

Q13. Please explain how you have, for illustrative purposes, incorporated Order 679 incentives in Exhibit No. SDG-3-4 (Statement BK-1).

A13. Exhibit SDG-3-4 Statement BK-1 has been modified to include an Incentive Section B for the incentives SDG&E has identified it may seek on future projects. The first three pages show the modifications made to incorporate incentive project costs in the derivation of the Base Period cost of service for both the transmission revenue requirements and Incentive transmission revenue requirements. Page 4 illustrates the derivation of the Annual Fixed Charge Rate, Forecast Capital Additions Revenue Requirements, and Plant Held for Future Use Revenue Requirement calculations. Page 5 shows the modifications made to derive the Incentive Forecast Capital Additions Revenues and Incentive Transmission CWIP Revenue Requirements. Page 6 of

Statement BK-1 summarizes the various revenue components that make up total annual transmission revenue requirements.

Q14. Please explain the incentive components that appear on page 1 of Statement BK-1.

A14. First, please note that Section B Incentives component does not contain any values for the following reasons: (1) Under the TO3 Settlement, SDG&E agreed to forgo filing for incentives during the TO3 term[1]; and (2) SDG&E will not reflect any project-specific incentive(s) in the applicable cycle of the TO4 Formula unless and until the Commission authorizes SDG&E to do so. Page 1, Section B develops the incentive prior year revenue requirements related to incentive projects. Line 38 reflects the book depreciation for an incentive project. Line 41, represents the incentive cost of capital grossed up for income taxes. The derivation of the incentive cost of capital rate comes from Statement AV – Incentive. Line 44 – Incentive Return and Associated Income Taxes--is derived by multiplying the incentive costs of capital rate by the incentive transmission rate base.

Line 48, is simply the sum of Prior Year Revenues and Incentive Prior Year Revenues to arrive at the Total Prior Year Revenue requirements. It is important to note that property taxes and any incremental Operation and Maintenance (O&M) costs related to future incentive projects are included in Section A as part of regular transmission revenues. The primary reason is due to the fact that it would be virtually impossible to calculate the incremental transmission O&M and A&G expenses for each individual incentive project.

Q15. Please explain page 2.

A15. Page 2 shows the derivation of SDG&E's transmission rate base. Section A shows the derivation of SDG&E's transmission rate base. Section B shows the derivation of incentive transmission rate base. The net transmission plant balances shown on lines 2 through 5 are brought forward from page 3, lines 16 through 20. The incentive net transmission plant balance shown on line 29 is brought forward from page 3, line 25.

Q16. Please explain Section B - Incentive Transmission Rate Base shown on Page 2.

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[1] SDG&E's agreement to forgo incentives for the Sunrise Powerlink Project survives the term of the TO3 Formula.

A16. Section B, calculates incentive transmission rate base and illustrates how SDG&E proposes to address CWIP incentive in rate base. Line 32, Incentive Transmission CWIP for incentive projects will be derived using a 13 month weighted average balance in the Base Period. A 13-month weighted average is used because it represents a close proxy to the Allowance for Funds Used during Construction we would no longer capitalize as a result of including CWIP in rate base. This information will be provided in Cost Statement AM (CWIP). Line 36 shows the accumulated deferred income taxes related to plant in-service incentive projects.

Q17. Please explain Page 3.

A17. Page 3 shows the derivation for both net transmission plant and incentive net transmission plant. Section A illustrates the derivation of net transmission plant and Section B shows the derivation of incentive net transmission plant.

Q18. Please explain Page 4.

A18. Section A of page 4 derives the Annual Fixed Charge Rate (AFCR) and calculates Forecast Plant Addition Revenue Requirements. The derivation of the forecast plant addition revenue requirements is based on the AFCR methodology currently used in TO3 Formula. The annual fixed charge rate shown on line 14 is derived by taking total prior year revenue requirements (line 10) divided by Gross Transmission Plant (line 12). The Forecast Plant Addition Revenue Requirements is derived by taking the product of AFCR (line 14) and Weighted Forecast Plant Additions (line 16). Section B derives the revenue requirements for Plant Held for Future Use (PHFU) in the Forecast period using the cost of capital rate. The derivation of the Cost of Capital Rate is further discussed in the testimony of Mr. Farinas (Exhibit No. SDG-6).

Q19. Please explain Page 5.

A19. Page 5, Section A reflects the derivation of the incentive $AFCR_{ROE}$ and incentive weighted forecast plant additions revenue requirements. The derivation of incentive AFCR applicable to incentive projects is very much similar to regular AFCR shown on page 4, line 14. With one minor exception, the Base Period revenues shown on line 3, page 5 is derived by recalculating the Base Period revenues shown on page 1, section A.

The recalculation of rate base for incentive project is simply the product of the incentive cost of capital rate and transmission rate base of $307.9 million.

Section B shows the derivation of the revenue requirements for CWIP incentive projects in the Forecast Period. Line 20, Transmission CWIP Incentive Projects, shall be calculated for each month based upon a 13-month weighted average balance. Line 24 reflects CWIP incentive Forecast Period plant addition (line 20) multiplied by the Cost of Capital rate (line 22) equals incentive CWIP transmission revenue requirements.

Q20. Please explain page 6.

A20. Page 6 simply summarizes and sets forth total Retail Transmission Revenue Requirements as shown.

Q21. Does SDG&E give illustrative examples of how these incentives will work in Statement BK-1?

A21. Yes. Raulin Farinas provides illustrative examples of how incentive revenues will be calculated under the TO4 Formula (See Exhibit No. SDG-6).

B. Other Miscellaneous Changes

Q22. Please explain the Other Miscellaneous Changes that affect revenues.

A22. Exhibit SDG-3-3 lists the other substantive changes made to Appendix VIII and briefly explains these changes.

1. Update of Transmission Related Uncollectible and Franchise Rate

Q23. Please explain why SDG&E changed the Transmission Related Uncollectible Rate from 0.266% to 0.141% as indicated in Exhibit SDG-3-3?

A23. At the time of SDG&E's TO3 Formula filing on December 1, 2006 the Transmission Related Uncollectible Rate was 0.266%. In December 2006, SDG&E filed its 2008 General Rate Case (GRC) application number 06-12-009 with the CPUC. The application was approved July 31, 2008 in decision number D.08.07.046, effective January 1, 2008. As a result of this change, as of January 1, 2008, SDG&E has been using the updated CPUC approved Transmission Related Uncollectible Rate of 0.141% in the derivation of its BTRR.

Q24. You indicate in Exhibit SDG-3-3 that the Transmission Related Uncollectible Rate of 0.141% may change pending approval of 2012 GRC filing.

A24. Yes, we are waiting for a decision on SDG&E's 2012 GRC filing Application No. 10-12-005 filed December 15, 2010 with CPUC. We are anticipating CPUC approval in the first half of 2013.

Q25. Please explain why SDG&E changed the Transmission Related Franchise Tax Rate of 1.01% to 1.0275%.

A25. The reason for this change is the same for Uncollectible expenses as explained in the previous response.

Q26. In Exhibit SDG-3-3 you also indicate that Transmission Related Franchise Tax Rate may change pending approval of 2012 GRC filing.

A26. Yes, we are awaiting a decision from the CPUC on SDG&E's 2012 GRC filing Application No. 10-12-005, filled December 15, 2010.

2. Effect of Appendix X Formula (Citizens) on TO4 BTRR

Q27. SDG&E has a currently-effective Appendix X Formula that allocates certain total Electric Division A&G expenses, property taxes and other costs to Citizens Sunrise Transmission, LLC (Citizens) related to a lease for 50% portion of the 30 mile Sunrise Border-East Line.[2] Do the total costs for Electric Division A&G expenses, property taxes, transmission O&M expense, and other costs used to determine TO4 BTRR include any Citizens costs?

A27. No. As set forth in the Citizens Appendix X Formula, all costs that are recorded in SDG&E's applicable FERC Form 1 accounts, which are used to develop BTRR under TO4, excludes any costs allocated to Citizens. Citizen's costs are recorded in separate FERC accounts pursuant to FERC's order related to SDG&E's booking of Citizens allocated costs. Also as indicated in the final order related to Docket ER12-1417-000, SDG&E agreed it would reconcile FERC approved costs in its BTRR filings and future Citizens Allocated filings under Appendix X to that both BTRR customers and Citizens were treated in the same manner in paying for allocated costs.

Q28. Does this conclude your testimony?

A28. Yes, it does.

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[2] On October 19, 2012, the Commission approved the Appendix X Formula in a Letter Order 141 FERC ¶ 61,054.

APPENDIX VIII

FORMULA FOR CALCULATING ANNUAL BASE TRANSMISSION REVENUE REQUIREMENTS UNDER SDG&E'S TRANSMISSION OWNER TARIFF

This Appendix VIII sets forth the formula for calculating the annual Base Transmission Revenue Requirement ("BTRR") and is organized into the following sections:

21. Incentive Abandoned Project Cost
~~19.~~22. Incentive Construction Work in Progress
~~20.~~23. Incentive Project
~~21.~~24. Incentive Return and Associated Income Taxes
25. Incentive Return on Equity
~~22.~~26. Incentive Transmission Plant
~~23.~~27. Incentive Transmission Plant Accumulated Deferred Income Taxes
~~24.~~28. Incentive Transmission Plant Depreciation Expense
~~25.~~29. Incentive Transmission Plant Depreciation Reserves
30. Incentive Transmission Plant Other Regulatory Assets/Liabilities
~~26.~~31. Incentive Weighted Forecast Plant Additions
~~27.~~32. Materials and Supplies
33. Municipal Franchise Tax Expense
34. Other Regulatory Assets/Liabilities
~~28.~~35. Payroll Taxes
~~29.~~36. Prepayments
~~30.~~37. Property Insurance
38. Property Taxes
~~31.~~39. Rate Effective Period
~~32.~~40. Return and Associated Income Taxes
41. Return on Equity
~~33.~~42. South Georgia Income Tax Adjustment
43. Total Plant in Service
~~34.~~44. Transmission Depreciation Reserve
~~35.~~45. Transmission, General, ~~and~~ Common, and Electric Misc. Intangible Plant Depreciation Expense
~~36.~~46. Transmission Operation and Maintenance Expense
47. Transmission Plant
48. Transmission Plant Depreciation Expense
~~37.~~49. Transmission Plant Held for Future Use
~~38.~~50. Transmission Related Abandoned ~~Cancelled~~ Project Costs
~~39.~~51. Transmission Related Abandoned ~~Cancelled~~ Project Cost Amortization Expense
52. Transmission Related Accumulated Deferred Income Taxes
~~40.~~53. Transmission Related A&G Expenses
~~41.~~54. Transmission Related Amortization of Excess Deferred Tax Liabilities
~~42.~~55. Transmission Related Amortization of Investment Tax Credits
~~43.~~56. Transmission Related Cash Working Capital
~~44.~~57. Transmission Related Common Plant
~~45.~~58. Transmission Related Common Plant Depreciation Expense
~~46.~~59. Transmission Related Common Plant Depreciation Reserve
~~47.~~60. Transmission Related Depreciation Reserve

~~48.~~61. Transmission Related General Plant
~~49.~~62. Transmission Related General Plant Depreciation Expense
~~50.~~63. Transmission Related General Plant Depreciation Reserves
~~51.~~64. Transmission Related Electric General and Common Plant Accumulated Deferred Income Taxes
~~52.~~65. Transmission Related Electric Miscellaneous Intangible Plant
~~53.~~66. Transmission Related Electric Intangible Plant Accumulated Deferred Income Taxes
67. Transmission Related Electric Miscellaneous Intangible Plant Amortization Expense
~~54.~~68. Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve

~~55.~~69. Transmission Related Material & Supplies
70. Transmission Related Municipal Franchise Tax Expense
71. Transmission Related Payroll Tax Expense
72. Transmission Related Prepayments
73. Transmission Related Property Taxes
74. Transmission Related Regulatory Debits
75. Transmission Related Revenue Credits
76. Transmission Related Uncollectible Expense
77. True-Up Period
78. Uncollectible Expense
79. Valley Rainbow Project Costs
80. Weighted Forecast Plant Additions

II. Calculation of Annual BaseTransmission Revenue Requirement

A. Return and Associated Income Taxes
B. ~~End Use Customer~~ Base Transmission Revenue Requirement
C. CAISO Base Transmission Revenue Requirement
D. True-Up Adjustment Calculation
E. Interest True-Up Adjustment Calculation

INTRODUCTION

This Appendix sets forth details with respect to the determination each year of San Diego Gas & Electric Company's ("SDG&E") Base Transmission Revenue Requirements used to derive the charges assessed by SDG&E to its End Use Customers ("$BTRR_{EU}$") and SDG&E's Base Transmission Revenue Requirements used to derive the transmission charges assessed by SDG&E pursuant to its Transmission Owner ("TO") Tariff and by the California Independent System Operator Corporation ("CAISO") pursuant to the CAISO Tariff ("$BTRR_{CAISO}$"). The $BTRR_{EU}$ and $BTRR_{ISO}$ for each Rate Effective Period will each be comprised of the following four ~~three~~ parts:

(i) the Prior Year Revenue Requirements ("PYRR")

(ii) the Forecast Period Capital Addition Revenue Requirements ("FC"); ~~and~~

(iii) a True-Up Adjustment

(iv) and an Interest True-Up Adjustment

The PYRR, FC and True-Up Adjustment, including the Interest True-Up Adjustment, shall be designed to reflect SDG&E's cost to own, operate and maintain its transmission facilities.

The PYRR will be an annual calculation based on the previous calendar year's data as shown in SDG&E's FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees, and Others ("Form 1") for that year and underlying ledger accounts. SDG&E shall make available the data reflected in the underlying ledger accounts used to determine SDG&E's PYRR in the annual informational filing described below. Valley Rainbow Project Costs (as defined below) shall be recovered commencing October 1, 2003 through September 2013 in accordance with this Appendix VIII as a component of PYRR as defined in Sections II.B and C hereof. The extent to which Transmission Related ~~Cancelled~~ Abandoned Project Cost (as defined below) will be included in SDG&E's formula rate will be determined on a case-by case basis pursuant to FERC authorization. CPUC Intervenor Funding Expense (as defined below) will be recovered as a component of PYRR for End Use Customers, but not for CAISO customers. The FC component will be an annual calculation based on an estimate of the revenue requirements associated with the transmission-related plant investments expected to be placed in service during the Forecast Period. The True-Up Adjustment for each True-Up ~~Rate Effective~~ Period will be an annual reconciliation of the difference between

(a) SDG&E's actual cost of providing transmission service during the applicable ~~most recent consecutive twelve-month period (the "~~True-Up Period~~") ending March 31 preceding that Rate Effective Period~~ as determined by application of the PYRR component of the formula rate; and

(b) actual revenues billed by SDG&E and paid by transmission customers for transmission service during the True-Up Period.

SDG&E shall submit to the Commission on or before August 15, 2013 ~~of each year~~ an informational filing (the "Informational Filing") showing the rates in effect for the Rate Effective Period beginning September 1, 2014 ~~of that year~~ and ending ~~through~~ August 31, 2015 ~~of the subsequent year~~. For subsequent cycles, SDG&E shall submit the Informational Filing on or before October 15 of each year, showing the rates in effect for the Rate Effective Period beginning January 1 and ending December 31 of that same year. Further, the Informational Filing shall show:

1. for the PYRR or Base Period, the average of the thirteen monthly balances for transmission-related plant investment and the transmission-

related plant retirements, reclassifications or additions causing such change; and

2. for the Forecast Period, any weighted forecast plant additions to transmission-related plant net of forecast retirements and reclassifications of Transmission Plant anticipated during that Forecast Period.

On or before June 15 or October 15, as applicable, SDG&E shall provide to the California Public Utilities Commission ("CPUC"), and make available to any other interested parties, by posting on its OASIS at www.sdge.com/rates-regulations/tariff information/open-access-ferc-tariffs ~~www.sdge.com\toforum,~~ a draft (the "Draft Informational Filing") of the Informational Filing ~~(not including individual project forecast plant additions)~~, for review, comment and discussion prior to the submission of the Informational Filing on August 15 or October 15. Additional Information on individual project forecast plant additions will be provided to the CPUC and to parties other than the CPUC requesting this information, subject to the execution by such party of a non-disclosure agreement accompanying the Protective Order that the Commission accepts concurrently its acceptance of the TO Formula, should SDG&E reasonably determine that such information should be treated as confidential to protect transmission system security or to prevent competitive cost information from being made publicly available. The Draft Informational Filing will also be available through a link to SDG&E's web page that is located on the CAISO OASIS accessible at www.caiso.com.

The Informational Filing shall not subject the formula set forth in this Appendix VIII to modification, but rather is contestable only with respect to prudence of the costs and expenditures included for recovery, as well as the accuracy of data and the consistency with the formula of the changes shown in the Informational Filing.

Any revisions to the information reflected in the Draft Informational Filing after it has been made available to the public but prior to submission of the Informational Filing to the Commission will be reflected in the Informational Filing, which will be filed no later than

August 15 or October 15 as applicable. Any revisions and refunds related to End Use Customer Base Transmission Revenue Requirements (“$BTRR_{EU}$”) resulting from a Commission Order will be reflected as provided by such a Commission Order in subsequent billings.

Revisions to CAISO Base Transmission Revenue Requirements (“$BTRR_{CAISO}$”) resulting from a Commission Order, will be made to billings pursuant to such Commission Order and as prescribed by the CAISO Tariff. All changes or corrections to rates that result in refunds will be with interest as calculated pursuant to 18 C.F.R. Section 35.19a.

In the event of a challenge to any cost reflected in charges derived under this Appendix VIII, SDG&E shall bear the burden of demonstrating that such costs and expenditures included for recovery were prudently incurred, as well as the accuracy and consistency with the formula of the information contained therein.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section 3 of SDG&E’s Transmission Owner Tariff, ~~in this Appendix VIII,~~ or in the CAISO Tariff, or in this Appendix VIII have the following definitions:

A. ALLOCATION FACTORS

~~1.~~ ~~Existing and New~~ High Voltage (HV) and Low Voltage (LV) -Allocation Factors: For purposes of SDG&E’s $BTRR_{ISO,}$ SDG&E will allocate its Base ~~t~~Transmission ~~r~~Revenue ~~r~~Requirements between ~~R~~recorded ~~Existing~~ High Voltage (“HV”) and ~~R~~recorded ~~Existing~~ Low Voltage (“LV”) Transmission Facilities based on the ratio of HV transmission plant, LV transmission plant and total gross transmission plant, plus ~~between~~

weighted ~~F~~forecast~~ed~~ HV and ~~F~~forecast~~ed~~ LV Transmission Facilities based on the respective percentages and in-service dates of such facilities owned by SDG&E, which are classified as such in accordance with CAISO's ~~guidelines~~ Tariff. ~~approved in Docket Nos. ER01-831-000 and ER00-2019-006~~

2. Seven-Element Adjustment Factor shall be a factor calculated by SDG&E to be applied by SDG&E to the relevant accounts, if necessary, for the purposes of properly functionalizing such accounts between transmission and distribution in accordance with the guidelines set forth in the Commission's Order No. 888, as those guidelines, as applicable to SDG&E, may be modified by the Commission from time to time. Electric Miscellaneous Intangible Plant will not be taken into account in the derivation of the Seven Element Adjustment Factor.

3. Transmission Plant Allocation Factor shall equal the ratio of the sum of SDG&E's total investment in (a) Transmission Plant, (b) Transmission Related General Plant and Transmission Related Common Plant and (c) Transmission Related Electric Miscellaneous Intangible Plant to SDG&E's Total Plant in Service.

4. Transmission Plant Property Insurance Allocation Factor shall equal the ratio of the sum of SDG&E's total investment in Transmission Plant and Transmission Related General Plant and Transmission Related Common Plant, to SDG&E's Total Plant in Service, excluding SDG&E's ownership share in the San Onofre Nuclear Generation Station ("SONGS").

5. Transmission Related Property Tax Allocation Factor shall equal the

ratio of SDG&E's total Transmission Plant and Transmission Related General Plant, and Transmission Related Common Plant, to SDG&E's Total Plant InService, excluding SONGS and Electric Miscellaneous Intangible Plant.

6. Transmission Wages and Salaries Allocation Factor shall equal the ratio of SDG&E's transmission-related direct wages and salaries to SDG&E's total direct wages and salaries, excluding administrative and general wages and salaries.

~~7. Transmission Plant Property Insurance Allocation Factor shall equal the ratio of the sum of SDG&E's total investment in Transmission Plant and Transmission Related General Plant and Transmission Related Common Plant, to SDG&E's Total Plant in Service, excluding SDG&E's ownership share in the San Onofre Nuclear Generation Station ("SONGS").~~

~~8. Existing and New HV and LVAllocation Factors: For purposes of SDG&E's $BTRR_{ISO,}$ SDG&E will allocate its transmission revenue requirements between Existing High Voltage ("HV") and Existing Low Voltage ("LV") Transmission Facilities and New HV and New LV Transmission Facilities based on the respective percentages and in-service dates of such facilities owned by SDG&E, which are classified as such in accordance with ISO's guidelines Tariff approved in Docket Nos. ER01-831-000 and ER00-2019-006~~

~~9. Transmission Related Property Tax Allocation Factor shall equal the~~

~~ratio of SDG&E's total Transmission Plant and Transmission Related General Plant, and Transmission Related Common Plant, to SDG&E's Total Plant In Service, excluding SONGS and Electric Miscellaneous Intangible~~ Plant.

B. TERMS

1. Accumulated Deferred Income Taxes shall equal the net of the deferred tax balance recorded in FERC Account Nos. 281-283 and the deferred tax balance recorded in FERC Account No. 190.

2. Administrative and General Expense (A&G) - Electric shall equal SDG&E's expenses recorded in FERC Account Nos. 920-935, excluding FERC Account No. 930.1 (General Advertising Expense). These expenses shall be either (a) allocated across applicable functions based on Transmission Wages and Salaries Allocation Factor ~~labor ratios~~ and/or (b) directly assigned to the transmission function where: (i) direct assignment is consistent with cost causation principles, (ii) the relationship between cost incurrence and cost responsibility is obvious and reviewable and (iii) direct assignment is reasonable and cost allocation is unreasonable, *e.g.*, it would be unreasonable to use a labor ratio to allocate costs to both distribution and transmission functions where the costs at issue have been affirmatively linked to the transmission function only. The dollar threshold for direct assignment shall be $5 Million per event for Account 925 expenses and $1Million per event for expenses related to the other referenced A&G accounts.

3. Amortization of Investment Tax Credits shall equal SDG&E's credits

recorded in FERC Account No. 411.4.

4. Amortization of Unamortized Loss on Reacquired Debt shall equal SDG&E's expenses recorded in FERC Account No. 428.1.

5. Annual Fixed Charge Rate ("AFCR") for both end use and CAISO customers shall be defined as reflected in Section B.3.1 ~~and Section C.3.1, respectively~~. ~~the rate multiplied by Weighted Forecast Plant Additions that yields Forecast Period revenue.~~

6. Base Period, ~~except for the initial Base Period,~~ shall be the calendar year for which SDG&E's most recent FERC Form 1 is available; except for the initial Base Period, which shall be the 12-month period ending May 31, 2012 ~~June 30, 2006~~.

~~6.~~7. CAISO Base Transmission Revenue Requirements ($BTTR_{ISO}$) shall be calculated as defined in Section 2.C.

~~7.~~8. Common Plant shall equal SDG&E's gross plant balance recorded in FERC Account Nos. 303 and 389 through 398.

~~8.~~9. Common Plant Depreciation Expense shall equal SDG&E's depreciation expenses related to Common Plant recorded in FERC Account Nos. 403, 404, and 405 in accordance with depreciation rates authorized by the CPUC.

~~9.~~10. Common Plant Depreciation Reserve shall equal SDG&E's depreciation reserve balance related to Common Plant recorded in FERC Account Nos. 108 and 111.

~~10.~~11. CPUC Intervenor Funding Expense shall equal those expenses recorded in FERC Account No. 928 incurred by SDG&E associated with its requirement to reimburse intervenors participating in CPUC regulatory proceedings involving transmission projects as ordered and approved by the CPUC. ~~With respect to the amount of CPUC Intervenor Funding Expense associated with the cancelled Valley Rainbow project that shall be recoverable pursuant to this Appendix VIII, such expense shall be limited to no more than $700,000. To the extent such actual expense is less than $700,000, the difference between the actual lower expense and the $700,000 limit shall be reconciled as part of the first True-Up Adjustment described in Section II.D of this Appendix VIII.~~

~~11. Depreciation Expense for Transmission Plant shall equal SDG&E's transmission expenses recorded in FERC Account Nos. 403, 404, and 405 pursuant to the following table:~~

~~**TO43 Transmission Plant Depreciation Rates**~~

~~FERC Account~~	~~Plant Rate~~	~~Net Cost of Removal Rate~~	~~Total Rate~~
~~352~~	~~1.97%~~	~~0.59%~~	~~2.56%~~
~~353~~	~~2.11%~~	~~0.21%~~	~~2.32%~~
~~354~~	~~1.23%~~	~~0.92%~~	~~2.15%~~
~~355~~	~~2.45%~~	~~1.96%~~	~~4.41%~~
~~356~~	~~1.47%~~	~~1.40%~~	~~2.87%~~
~~357~~	~~1.76%~~	~~0.79%~~	~~2.55%~~
~~358~~	~~2.53%~~	~~0.25%~~	~~2.78%~~
~~359~~	~~1.54%~~	~~0.00%~~	~~1.54%~~
~~Composite Depreciation Rate~~	~~1.92%~~	~~0.73%~~	~~**2.65%**~~

~~To the extent that SDG&E seeks to change the amortization rates in Account No. 405 (applicable to transmission land rights), SDG&E shall make a Section 205 filing explicitly requesting such rate treatment.~~

12. Electric Miscellaneous Intangible Plant shall equal SDG&E's costs recorded in FERC Account No. 303 related to Electric Miscellaneous Intangible Plant.

13. Electric Miscellaneous Intangible Plant Amortization Expense shall equal

SDG&E's costs recorded in FERC Account No. 404 related to the amortization of Electric Miscellaneous Intangible Plant.

14. Electric Miscellaneous Intangible Plant Amortization Reserve shall equal SDG&E's costs recorded in FERC Account No. 111 related to the amortization reserve of Electric Miscellaneous Intangible Plant.

15. End Use Customer Base Transmission Revenue Requirement ($BTRR_{eu}$) shall be calculated as defined in Section 2, B.1 to B.5.

16. Forecast Period with respect to each twelve month Rate Effective Period, with the exception of Cycles 1 and 2, shall be the period beginning ~~April~~ January 1, just after the Base Period, and ending the following year on December 31, which corresponds to the last month of the ~~of the calendar year in which that~~ Rate Effective Period. ~~begins, through ending of the Rate Effect Period,~~ For Cycle 1, the Forecast Period will be June 1, 2012 through August 31, 2014. For Cycle 2, the Forecast Period will be January 1, 2014 to August 31, 2015. ~~except that for the Rate Effect Period ending August 31, 2008, the Forecast Period shall be the period beginning July 1, 2006 and ending June 30, 2008.~~

17. General Plant shall equal SDG&E's gross plant balance recorded in FERC Account Nos. 389-399.

18. General Plant Depreciation Expense shall equal SDG&E's depreciation expenses related to General Plant recorded in FERC Account Nos. 403, 404, and 405 in accordance with depreciation rates authorized by the CPUC.

19. General Plant Depreciation Reserve shall equal SDG&E's depreciation reserve balance related to General Plant recorded in FERC Account Nos. 108 and 111.

20. Incentives refer to any of the items delineated in FERC Order No. 679, as may be modified from time to time, including the following:

a) Incentive Return on Equity (ROE)

~~a)~~b) 100% of Construction Work in Progress (CWIP) in rate base.

~~b)~~c) 100% recovery of Abandoned Project Costs

21. Incentive Abandoned Project Cost shall include costs associated with abandoned projects for which SDG&E is authorized to collect under FERC Order NO. 679. These costs shall be recorded in FERC Account No.426.5 (Other Deductions).

22. Incentive Construction Work in Progress shall be construction work in progress for which SDG&E is authorized to collect Incentives under FERC Order No. 679. These costs shall be recorded in FERC Account NO. 107.

~~22.~~23. Incentive Project shall be a transmission capital project permitted by FERC Order No. 679, as it may be modified from time to time.

~~23.~~24. Incentive Return and Associated Income Taxes shall equal the product of the Incentive Transmission Rate Base and Incentive Cost of Capital Rate, as defined in Section II. A, below.

~~24.~~25. Incentive Return on Equity shall equal the Return on Equity that the FERC authorizes SDG&E to collect on Incentive Project(s).

26. Incentive Transmission Plant shall be transmission plant, which includes incentive projects for which SDG&E is authorized to collect Incentives under FERC Order No. 679.

27. Incentive Transmission Plant Accumulated Deferred Income Taxes shall equal the balance of Incentive Transmission Plant Accumulated Income Taxes applicable to Incentive Transmission Plant, as reflected in a footnote to SDG&E's annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing. Total Incentive Transmission Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.

28. Incentive Transmission Plant Depreciation Expense shall equal SDG&E's depreciation expenses related to Incentive Transmission Plant recorded in FERC Account Nos. 403, 404, and 405 in accordance with depreciation rates authorized by the CPUC.

29. Incentive Transmission Plant Depreciation Reserve shall equal the balance of incentive transmission reserves recorded in FERC Account Nos. 108 and 111 applicable to Incentive Transmission Plant.

~~25.~~30. Incentive Transmission Plant Other Regulatory Assets/Liabilities shall equal SDG&E's electric balance of any Other Regulatory Assets/Liabilities applicable to Incentive Transmission Plant.

~~26.~~31. Incentive Weighted Forecast Plant Additions for any Forecast Period shall be the estimated capital investment associated with Incentive Transmission Plant SDG&E anticipates placing in service during such Forecast Period. Such estimated capital investment shall be calculated using the same methodology for Weighted Forecast Plant Additions defined in Section 1, Definitions.

~~27.~~32. Materials and Supplies shall equal SDG&E's balance of total electric Materials and Supplies recorded in FERC Account No. 154, excluding those materials and supplies assigned to construction as reflected on SDG&E Form 1.

33. Municipal Franchise Tax Expense shall equal the amounts recorded in FERC Account No. 927.

~~28.~~34. Other Regulatory Assets/Liabilities shall equal amounts recorded in FERC Account No. 182.3 that the Commission has accepted for recovery under Section 205 of the Federal Power Act (FPA). Other Regulatory Assets/Liabilities for the initial Rate Effective Period shall be zero.

~~29.~~35. Payroll Taxes shall equal those payroll tax expenses recorded in FERC Account No. 408.1.

~~30.~~36. Prepayments shall equal SDG&E's prepayment balance recorded in FERC Account No. 165.

~~31.~~37. Property Insurance shall equal SDG&E's expenses recorded in FERC Account No. 924.

~~32.~~38. Property Taxes shall equal SDG&E's expense recorded in FERC Account No. 408.1.

~~33.~~39. Rate Effective Period shall be a 12 month calendar year period; provided, however, that for Cycle1, the Rate Effect Period shall begin September 1, 2013 and end August 31, 2014 and for Cycle 2, the Rate Effective Period shall begin September 1, 2014 and end December 31, 2015.

~~34.~~40. Return and Associated Income Taxes shall equal the product of the Transmission Rate Base and Cost of Capital Rate, as defined in Section II below.

~~35.~~41. Return on Equity shall be 11.3%.

~~36.~~42. South Georgia Income Tax Adjustment shall equal the amount set forth in the applicable FERC Form 1. ~~an increase in income tax expense that normalizes tax benefits previously flowed through to End Use Customers and for purposes of the BTRR$_{EU}$ shall be an annual amount equal to $5,178,000. The final year for the South Georgia Income Tax Adjustment for Federal and State will be 2017.~~

~~37.~~43. Total Plant in Service shall equal SDG&E's total gross plant balance recorded in FERC Account Nos. 301 through 399.

~~38.~~44. Transmission Depreciation Reserve shall equal SDG&E's transmission reserve balance recorded in FERC Account Nos. 108 and 111.

45. Transmission, General, ~~and~~ Common Plant Depreciation Expense and Electric Miscellaneous Intangible Amortization Expense shall equal the sum of (a) Depreciation Expense for Transmission Plant, plus an allocation of General and Common Plant Depreciation Expense calculated by multiplying both General Plant Depreciation and Common Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor; plus (b) Electric Miscellaneous Intangible Amortization Expense directly assigned to transmission, consistent with the cost causation principles as defined in Term 66.

~~39.~~46. Transmission Operation and Maintenance Expense shall equal

SDG&E's expenses recorded in FERC Account Nos. 560-5734, minus transmission costs recorded in FERC Account Nos. 561.4 and 561.8, minus transmission costs currently recorded in FERC Account No. 565 (Transmission of Electricity ~~By~~ by Others) relating to the purchase of power on behalf of or to serve SDG&E's bundled retail customers, minus ISO Grid Management Charge expenses recorded in these accounts, and minus expenses currently recorded in FERC Account No. 566 that are not transmission related, including, but not limited to, Reliability Must Run and Market Redesign Technology Update ("MRTU") costs,~~Out of Market Contract Costs, ISO Grid Management Charge expenses,~~ Transmission Revenue Balancing Account Adjustment ("TRBAA") expenses, and Transmission Access Charge Balancing Account Adjustment expenses ("TACBAA").

~~40.~~47. Transmission Plant shall equal SDG&E's Gross Plant balance recorded in FERC Account Nos. 350-359, excluding the portion of any facilities, the cost of which is directly assigned under the CAISO ~~Section 8.1.2 of SDG&E's TO~~ Tariff.

~~41.~~48. Transmission Plant Depreciation Expense ~~for Transmission Plant~~ shall equal SDG&E's transmission expenses recorded in FERC Account Nos. 403, 404, and 405 pursuant to the TO4 authorized ASL, Iowa Curve, and FNS% for each FERC subaccount as shown in the following table:

TO4 Transmission Plant Depreciation Rates

FERC Subaccount	Description	Proposed *ASL	Proposed Iowa Curve	Illustrative Plant Rate	Proposed **FNS %	Illustrative Net COR ***Rate	Illustrative Total Rate
E0135210	"Other"	72	R2	1.36%	-60%	0.82%	2.18%
E0135220	"SWPL"	72	R2	1.01%	-60%	0.61%	1.62%
E0135260	"SRPL"	72	R2	1.39%	-60%	0.84%	2.23%
E0135310	"Other"	50	R1	2.20%	-60%	1.32%	3.52%
E0135320	"SWPL"	50	R1	2.51%	-60%	1.51%	4.02%
E0135340	"Palomar"	50	R1	2.03%	-60%	1.22%	3.25%
E0135360	"SRPL"	50	R1	2.01%	-60%	1.21%	3.22%
E0135410	"Other"	70	R5	1.57%	-100%	1.57%	3.13%
E0135420	"SWPL"	70	R5	1.33%	-100%	1.33%	2.65%
E0135460	"SRPL"	70	R5	1.47%	-100%	1.47%	2.93%
E0135510	"Other"	45	R1.5	2.33%	-100%	2.33%	4.65%
E0135520	"SWPL"	45	R1.5	2.54%	-100%	2.54%	5.08%
E0135560	"SRPL"	45	R1.5	2.26%	-100%	2.26%	4.53%
E0135610	"Other"	58	S0	1.60%	-100%	1.60%	3.20%
E0135620	"SWPL"	58	S0	0.88%	-100%	0.88%	1.77%
E0135660	"SRPL"	58	S0	1.75%	-100%	1.75%	3.51%
E0135700	"Other & SWPL"	60	R5	1.68%	-45%	0.75%	2.43%
E0135760	"SRPL"	60	R5	1.69%	-45%	0.76%	2.45%
E0135800	"Other & SWPL"	50	R3	1.89%	-10%	0.19%	2.08%
E0135860	"SRPL"	50	R3	2.03%	-10%	0.20%	2.23%
E0135910	"Other"	60	SQ	1.65%	0%	0.00%	1.65%
E0135920	"SWPL"	60	SQ	1.44%	0%	0.00%	1.44%
E0135960	"SRPL"	60	SQ	1.68%	0%	0.00%	1.68%

* ASL – Average Service Life ** FNS – Future Net Salvage *** COR – Cost of Removal

SDG&E reserves the right to update rates over time using the authorized parameters set forth above. To the extent that SDG&E seeks to change the authorized parameters, ~~mortization rates in Account No. 405 (applicable to transmission land rights),~~ SDG&E shall make a Section 205 filing explicitly requesting authorization to change such parameters.~~rate treatment~~.

~~42.~~49. Transmission Plant Held for Future Use shall equal SDG&E's balance recorded in FERC Account No. 105 for projects approved by the CPUC. Gain or loss on the sale of plant held for future use shall be recorded in FERC Account Nos. 411.6 and 411.7.

~~43.~~50. Transmission Related Abandoned ~~Cancelled~~ Project Cost shall equal an amount, other than Valley Rainbow Project Costs, relating to abandoned ~~cancelled~~ transmission projects that is recorded in FERC Account No. 182.2. The ratemaking treatment to be afforded such costs shall be determined by the Commission on the basis of a filing made by SDG&E with the Commission under Section 205 of the FPA for recovery under this Appendix VIII. In the Section 205 of the FPA proceeding, SDG&E reserves its right to request recovery of up to 100% of the Transmission Related Abandoned Project Cost and parties reserve their right to contest 100% recovery as provided for in this Appendix VIII. Transmission Related Abandoned ~~Cancelled~~ Project Cost for the initial Rate Effective Period shall be zero.

~~44.~~51. Transmission Related Abandon ~~Cancelled~~ Project Cost Amortization Expense shall equal the annual amortization expense recorded in FERC Account No. 407 related to Transmission Related Abandoned ~~Cancelled~~ Project Cost.

~~45.~~52. Transmission Related Accumulated Deferred Income Taxes shall equal the balance of Transmission Plant Accumulated Deferred Income taxes, plus the balance of Transmission Related Electric General and

Common Plant Accumulated Deferred Income Taxes, plus Transmission Related Electric Miscellaneous Intangible Plant Deferred Income Taxes. As reflected in a footnote to SDG&E's annual FERC Form 1 which SDG&E shall reference by page in its Informational Filing. Total Transmission Related Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.

53. Transmission Related A&G Expenses shall equal (1) directly assigned transmission A&G Electric as set forth in Section I.B.2. plus (2) other A&G expenses that will be allocated to transmission using the Transmission Wages and Salaries Allocation Factor, specifically ~~SDG&E"s~~ the Administrative and General Expenses included in FERC Account Nos. 920-935, excluding (a) directly assigned transmission A&G expenses and (b) non-transmission-related expenses, which include but are not limited to non-transmission-related expenses in FERC Account No. 924 (Property Insurance), FERC Account No.925 (Damages and Injuries), FERC Account No. 927 (Franchise Requirements), FERC Account No. 930.2 (Miscellaneous General Expenses), FERC Account No. 935 (Maintenance of General Plant), and any CPUC Intervenor Funding Expense recorded in FERC Account No. 928 (Regulatory Commission Expenses), multiplied by the Transmission Wages and Salaries Allocation Factor, plus (3~~2~~) Property Insurance in FERC Account No. 924, excluding insurance costs related to nuclear plant serving SDG&E's bundled retail customers, multiplied by the Transmission Plant Property Insurance Allocation Factor, minus (4~~3~~) CPUC mandated costs recovered through retail rates; provided,

however, if the rate(s) of expense accrual for SDG&E's post-employment benefits other than pensions ("PBOP"), as recorded in FERC Account No. 926, change from those expense levels recorded in SDG&E's February 2013 ~~December 1, 2006~~, TO4 F~~f~~iling ~~Docket Number Number ER07-284-000~~, SDG&E may reflect such changes in charges under this formula only to the extent approved by the Commission under Section 205 of the FPA.

~~46.~~54. Transmission Related Amortization of Excess Deferred Tax Liabilities shall equal an amount recorded in FERC Account Nos. 190, 282, and 283 related to transmission as reflected in a footnote in SDG&E's annual FERC Form 1 as referenced by page in its annual Informational Filing.

~~47.~~55. Transmission Related Amortization of Investment Tax Credits shall equal the amount set forth in the applicable FERC Form 1~~$522,575~~ until fully amortized. ~~in 2018, plus amortization of any additional investment tax credits related to transmission that may accrue after March 7, 2003.~~ SDG&E shall reflect in a footnote in its annual FERC Form 1 any Transmission Related Amortization of Investment Tax Credits, which SDG&E shall reference by page in its annual Informational Filing.

~~Transmission Related Cancelled Project Cost shall equal an amount, other than Valley Rainbow Project Costs, relating to cancelled transmission projects that are recorded in FERC Account No. 182.2. The ratemaking treatment to be afforded such costs shall be determined by the Commission on the basis of a filing made by SDG&E with the Commission under Section 205 of the FPA for recovery under this Appendix VIII. Transmission Related Cancelled Project~~

~~Cost for the Initial Rate Effective Period shall be zero.~~

~~Transmission Related Cancelled Project Cost Amortization Expense shall equal the annual amortization expense recorded in FERC Account No. 407 related to Transmission Related Cancelled Project Cost.~~

~~48.~~56. Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Transmission Operations and Maintenance and Transmission Related A&G Expenses.

~~49.~~57. Transmission Related Common Plant shall equal SDG&E's balance of investment in Common Plant multiplied by the Transmission and Salaries Allocation Factor.

~~50.~~58. Transmission Related Common Plant Depreciation Expense shall equal the balance of SDG&E's Common Plant Depreciation Expense recorded in FERC Account Nos. 403, 404, and 405 multiplied by the Transmission Wages and Salaries Allocation Factor.

~~51.~~59. Transmission Related Common Plant Depreciation Reserve shall equal that portion allocated to transmission using the Transmission Wages and Salaries Allocation Factor.

~~52.~~60. Transmission Related Depreciation Reserves shall equal the balance of Transmission Depreciation Reserves, plus the balance of Transmission Related General Plant Depreciation Reserves, plus Transmission Related Common Plant Depreciation Reserves, plus the balance of Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserves.

61. Transmission Related General Plant shall equal SDG&E's balance of investment in General Plant multiplied by the Transmission

Wages & Salaries Allocation Factor.

62. Transmission Related General Plant Depreciation Expense shall equal the balance of SDG&E's General Plant Depreciation Expense recorded in FERC Account Nos. 403, 404, and 405 multiplied by Transmission Wages & Salaries Allocation Factor.

~~53.~~63. Transmission Related General Plant Depreciation Reserves shall equal the balance in General Plant Depreciation Reserves multiplied by the Transmission Wages & Allocation Factor.

~~54.~~64. Transmission Related Electric General and Common Plant Accumulated Deferred Income Taxes shall equal SDG&E's total General and Common Accumulated Deferred Income Taxes, as reflected in a footnote to SDG&E's annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing, multiplied by the Transmission Wages and Salaries Allocation Factor. Such Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.

~~55.~~65. Transmission Related Electric Miscellaneous Intangible Plant shall equal the total ~~SDG&E's balance~~ amount of Electric Miscellaneous Intangible Plant recorded in FERC Account No. 303 associated with transmission ~~multiplied by the Transmission Wages and Salaries Allocation Factor.~~ as a result of either (a) an allocation to transmission function based on Transmission Wages and Salaries Allocation Factor or (b) directly assigned to the transmission function where: (i) direct assignment is consistent with cost causation principles, (ii) the relationship between cost incurrence and cost responsibility is obvious and reviewable and (iii) direct assignment is reasonable and cost allocation is unreasonable, *e.g.*, it would be unreasonable to use a labor ratio to allocate the balance to both distribution and transmission functions where the costs at issue have been affirmatively linked to the transmission function only.

~~56.~~66. Transmission Related Electric Miscellaneous Intangible Plant Accumulated Deferred Income Taxes shall be the amount reflected in a footnote to SDG&E's annual FERC Form 1 which shall be referenced by page in its Informational Filing. Such Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.

~~57.~~67. Transmission Related Electric Miscellaneous Intangible Plant Amortization Expense shall equal SDG&E's balance recorded in FERC Account No.404 and shall be accounted for as set forth in Section I.B.65. ~~multiplied by the Transmission Wages and Salaries Allocation Factor. and shall be directly assigned to Transmission, consistent with cost causation principles~~.

~~58.~~68. Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve shall equal SDG&E's balance of Electric Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account No.111 and shall be accounted for in the manner set forth in Section I.B.65. ~~multiplied by the Transmission Wages and~~

~~Salaries Allocation Factor.~~ SDG&E shall footnote these amounts in its annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing.

~~59.~~69. Transmission Related Materials & Supplies shall equal SDG&E's electric balance of Materials and Supplies multiplied by the Transmission Plant Allocation Factor.

~~60.~~70. Transmission Related Municipal Franchise Tax Expense shall equal: a) the Base Transmission Revenue Requirement ("BTRR") multiplied by the Municipal Franchise Tax Expense rate that the CPUC authorizes from time to time, currently 1.02751~~1~~%, which shall be recovered as part of the BTRR rates, plus b) an amount of Municipal Franchise Tax Expense that the CPUC authorizes SDG&E to collect from customers who reside in the City of San Diego. This latter amount shall be reflected on the electric bills of customers residing in the City of San Diego.

~~61.~~71. Transmission Related Payroll Taxes Expense shall equal SDG&E's total electric Payroll Taxes expense recorded in FERC Account No. 408.1, multiplied by the Transmission Wages and Salaries Allocation Factor.

~~62.~~72. Transmission Related Prepayments shall equal SDG&E's electric balance of prepayments recorded in FERC Account No. 165 multiplied by the Transmission Plant Allocation Factor.

~~63.~~73. Transmission Related Property Taxes shall equal Property Taxes, excluding property taxes directly assigned to SONGS, multiplied by the Transmission Related Property Tax Allocation Factor. SDG&E shall footnote in its annual FERC Form 1 the directly assigned property taxes attributable to SONGS, which SDG&E shall reference by page in its Informational Filing.

~~64.~~74. Transmission Related Regulatory Debits shall equal SDG&E's amortization expense associated with Other Regulatory Assets/Liabilities debited to FERC Account No. 407.3 that the Commission has accepted for recovery under Section 205 of the FPA. Transmission Related Regulatory Debits for the initial Rate Effective Period shall be zero.

~~65.~~75. Transmission Related Revenue Credits shall include Rents Received from Electric Property recorded in FERC Account No. 454 associated with such Electric Property included in Transmission Rate Base as defined in Section II.A below, plus Other Electric Revenues recorded in FERC Account No. 456 that recover the cost associated with SDG&E's Transmission Rate Base, excluding any revenues credited through the TRBAA or another mechanism.

~~66.~~76. Transmission Related Uncollectible Expense shall equal the Base Transmission Revenue Requirement$_{EU}$ multiplied by the allowance for uncollectible expenses approved from time to time by the CPUC. Currently,~~Initially,~~ the rate is 0.141~~266~~%.

~~67.~~77. True-Up Period shall be 12 months ended December ~~March~~ 31 of each year; *provided, however*, that for Cycle 2, the ~~initial~~ True-Up Period shall be ~~the 9~~ 4 months September 1, 2013 through ~~ending March~~ December

31, 201~~3~~08.

~~68.~~78. Uncollectible Expense shall equal SDG&E's charges for uncollectible accounts recorded in FERC Account No. 904.

~~69.~~79. Valley Rainbow Project Costs shall equal $1,892,694, which represents the annual amortization~~,~~ over a ten-year period, ending September 2013 of certain costs associated with the cancelled Valley Rainbow transmission project. The Valley Rainbow cost will expire September 30, 2013 and an amount of $157,724 will appear in TO4 C2 True-Up Adjustment. After September 2013, the cost of Valley Rainbow will be fully recovered.

~~70.~~80. Weighted Forecast Plant Additions for any Forecast Period, except for Cycles 1 and 2, shall be the estimated capital investment in new Transmission Plant, Transmission Plant Held for Future Use, and Transmission Related General and Common Plant SDG&E anticipates placing in service during such Forecast Period. Such estimated capital investments shall be determined for each month of the Forecast Period as described herein and each such estimated capital investment shall be multiplied by a weighting factor such that the magnitude of such capital investment as reflected in the determination of SDG&E's transmission revenue requirement pursuant to this Appendix VIII formula reflects the number of months during the Forecast Period those investments in new transmission facilities are actually in service. Any new transmission facilities expected to be placed in service during the Forecast Period but prior to the end of the first month of the following Rate Effective Period, i.e. January 31, ~~September 30,~~ shall be assigned a weighting factor of 1.00. Any new transmission facilities expected to be placed in service during the Forecast Period as of the beginning of the second month of the Rate

Effective Period, i.e. February ~~October~~ 1, or thereafter through and including December ~~August~~ 31 ~~of the following year~~, shall be assigned a weighting factor based on the number of months during the Rate Effective Period for which those facilities are expected to be in service divided by 12. Thus, for example, a plant addition expected to be placed in service in February ~~October~~ of the Rate Effective period would be assigned a weighting factor of 11 divided by 12 or 0.917.

For Cycles 1 and 2, the weighted forecast plant additions for the Forecast Period shall be calculated in the same manner as described above except that the first month of the Rate Effective Period shall be September 2013 for Cycle 1 and September 2014 for Cycle 2.

II. CALCULATION OF ANNUAL BASE TRANSMISSION REVENUE REQUIREMENTS

A. Return and Associated Income Taxes

Return and Associated Income Taxes shall equal the product of the Transmission Rate Base and a Cost of Capital Rate, which are defined as follows.

1. Transmission Rate Base

The Transmission Rate Base will be calculated as follows:

(a) Transmission Plant based on the weighted average of the thirteen monthly balances, plus

(b) Transmission Related General Plant based on the average of the sum of the beginning and end of year balances, plus

(c) Transmission Related Common Plant based on the average of the sum of the beginning and end of year balances, plus

(d) Transmission Related Electric Miscellaneous Intangible Plant based on the average of the sum of the beginning and end of year balances, minus

(e) ~~Transmission Plant Held for Future Use based on the average of thirteen monthly balances,~~ minus

(f) Transmission ~~Related~~ Depreciation Reserve based on the weighted average of the thirteen monthly balances, minus

(g) Transmission Related General Plant Depreciation Reserve based on the average of the sum of the beginning and end of year balances, minus

(h) Transmission Related Common Plant Depreciation Reserve based on the average of the sum of the beginning and end of the year balances, minus

(i) ~~Transmission Related Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of the year balances, minus~~

(j) ~~Transmission Related General and Common Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of the year balanaces, minus~~

(k) Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve based on the average of the sum of the beginning and end of year balances, plus

(l) Transmission Plant Held for Future Use based on the weighted average of thirteen monthly balances, plus

(m) Transmission Plant ~~Related~~ Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of year balances, minus

(n) Transmission Related General and Common Plant Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of year balances, minus

(o) Transmission Related Electric Miscellaneous Intangible Plant Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of year balances, plus

(p) Other Regulatory Assets/Liabilities, plus

(q) Transmission Related Prepayments based on the weighted average of the sum of the thirteen monthly balances, plus

(r) Transmission Related Materials and Supplies based on the weighted average of the thirteen monthly balances, plus

(s) Transmission Related Cash Working Capital, plus

(t) Transmission Related Abandoned ~~Cancelled~~ Project Cost, minus

~~(t)~~(u) Transmission Abandoned Plant Accumulated Deferred Income Taxes,

Where:

(1) Transmission Plant shall be as defined in Section I.B, Terms ~~Definitions~~.

(2) Transmission Related General Plant shall be as defined in Section I.B, Terms. ~~Shall equal SDG&E's balance of~~

~~investment in General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.~~

(3) Transmission Related Common Plant shall be as defined in Section 1.B, Terms. ~~Shall equal SDG&E's balance of investment in Common Plant multiplied by the Transmission Wages and Salaries Allocation Factor.~~

(4) Transmission Related Electric Miscellaneous Intangible Plant shall be as defined in Section 1.B, Terms. ~~Shall equal SDG&E's balance of Electric Miscellaneous Intangible Plant recorded in FERC Account No. 303 multiplied by the Transmission Wages and Salaries Allocation Factor.~~

(5) ~~Transmission Plant Held for Future Use shall be as defined in Section I, Definitions.~~ Moved – see 10 below.

(6) Transmission ~~Related~~ Depreciation Reserve shall be as defined in Section 1.B, Terms. ~~Shall equal the balance of Transmission Depreciation Reserves plus the balance of Transmission Related General Plant Depreciation Reserve, plus Transmission Related Common Plant Depreciation Reserve. Transmission related General Plant Depreciation Reserve and Transmission related Common Plant Depreciation Reserve shall equal the product of General Plant Depreciations Reserve plus Common Plant Depreciation Reserve, and the Transmission Wages and Salaries Allocation Factor.~~

(7) Transmission Related General Plant Depreciation Reserve shall be as defined in Section 1.B, Terms.

(8) Transmission Related Common Plant Depreciation Reserve shall be as defined in Section 1.B, Terms.

(9) Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve shall be as defined in Section 1.B, Terms.

(10) Transmission Plant Held for Future Use shall be as defined in Section I.B, Terms~~Definitions~~.

(11) Transmission Related Accumulated Deferred Income Taxes shall as defined in Section 1.B, Terms. ~~Shall equal the balance of Total Transmission Accumulated Deferred Income Taxes, as reflected in a footnote to SDG&E's annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing. Total Transmission Related Accumulated Deferred Income Taxes shall exclude Financial Accounting Standard 109 costs.~~

(12) ~~Transmission Electric General and Common Accumulated Deferred Income Taxes shall equal SDG&E's total General and Common Plant Accumulated Deferred Income Taxes, as reflected in a footnote to SDG&E's annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing, multiplied by the Transmission Wages and Salaries Allocation Factor. Such Accumulated Deferred Income Taxes shall exclude Financial Accounting Standards 109 costs.~~

(13) ~~Transmission Related Electric Miscellaneous Intangible Plant Amortization Reserve shall equal SDG&E's balance of Electric Miscellaneous Intangible Plant Amortization Expense recorded in FERC Account No. 111, multiplied by the Transmission Wages & Salaries Allocation Factor, SDG&E shall footnote these amounts in its annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing.~~

(14) ~~Transmission Related Electric Miscellaneous Intangible Plant Accumulated Deferred Income Taxes shall equal SDG&E's balance of Electric Miscellaneous Intangible Plant Accumulated Deferred Income Taxes recorded in FERC Account Nos. 281-283 and the deferred tax balance recorded in FERC Account No. 190, multiplied by the Transmission Wages & Salaries Allocation Factor. SDG&E shall footnote these amounts in its annual FERC Form 1, which SDG&E shall reference by page in its Informational Filing.~~

(15) ~~Transmission Related~~ Other Regulatory Assets/Liabilities ~~Debits~~ shall be as defined in Section 1.B, Terms. ~~Assets/Liabilities shall equal SDG&E's electric balance of any Other Regulatory Assets/Liabilities.~~

(16) Transmission Related Prepayments shall be as defined in Section 1.B, Terms. ~~Shall equal SDG&E's electric balance of prepayments multiplied by the Transmission Plant Allocation Factor.~~

(17) Transmission Related Materials and Supplies shall be as defined in Section 1.B, Terms. ~~Shall equal SDG&E's electric balance of Materials and Supplies multiplied by the Transmission Plant Allocation Factor.~~

(18) Transmission Related Cash Working Capital shall be as defined in Section 1.B, Terms. ~~Shall be a 12.5% allowance (45 days/360 days) of Transmission Operation and Maintenance Expense, and Transmission Related A&G Expense.~~

(19) Transmission Related Abandoned ~~Cancelled~~ Project Cost shall be as defined ~~have the meaning set forth~~ in Section I.B, Terms ~~B.37 hereof~~.

~~(19)~~(20) Transmission Related Abandon Project Accumulated Deferred Income Taxes shall be as defined in Section 1.B, Terms.

2. **Incentive Transmission Rate Base**

The Incentive Transmission Rate Base shall be calculated as follows:

a) Incentive Transmission Plant based on a 13 month weighted average balances, minus

~~a)~~b) Incentive Transmission Plant Depreciation Reserve based on the a 13 month weighted average balance, plus

~~b)~~c) Incentive Transmission Construction Work in Progress based on a 13 month weighted average balance, minus

d) Incentive Transmission Plant Accumulated Deferred Income Taxes based on the average of the sum of the beginning and end of year balances.

Where,

1. Incentive Transmission Plant shall be as defined in Section 1.B. Terms.
2. Incentive Transmission Plant Depreciation Reserves shall be as defined in Section 1.B, Terms.
3. Incentive Transmission Construction Work in Progress shall be as defined in Section 1.B, Terms.
4. Incentive Transmission Plant Accumulated Deferred Income Taxes shall be as defined in Section 1.B, Terms.

3. **Cost of Capital Rate**

The Cost of Capital Rate will equal (a) SDG&E's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income tax.

(a) The Weighted Cost of Capital will be calculated based upon ~~the~~ end-of-period~~roduct~~ capital structure as of December 31 and will be equal to the weighted cost of SDG&E's (i) long term debt, (ii) preferred stock and (iii) common equity with each such cost being weighted by the percentage that each such capital component is to SDG&E's total capital. (Thus, for example, if long term debt represents 40.00% of total capital and has a cost of 10.00 %, the weighted long term debt cost component would be 4.00 %). SDG&E's total capital shall equal the sum of SDG&E's balance of long term debt, preferred stock issued and outstanding, and common stock issued and outstanding. The respective costs of these components will be calculated as follows:

(i) the long-term debt component, shall be the actual weighted average embedded cost to maturity of SDG&E's long-term debt then outstanding.

The actual weighted average embedded cost to maturity of SDG&E's long-term debt shall equal:

(1) The sum of (a) FERC Account No. 427 - Interest on Long-Term Debt; (b) plus FERC Account No. 428 - Amortization of Debt Discount and Expenses; (c) plus FERC Account No. 428.1 - Amortization of Unamortized Loss on Reacquired Debt; (d) less FERC Account No. 429 - Amortization of Premium on Debt – Credit; and (e) less FERC Account No. 429.1 - Amortization of Gain on Reacquired Debt – Credit

divided by

(2) the sum of the following accounts: (a) FERC Account No. 221 - Bonds; (b) less FERC Account No. 222 - Reacquired Bonds; (c) plus FERC Account No. 224 - Other Long-Term Debt plus (d) FERC Account No. 225 – Unamortized Premium on Long Term Debt, less (e) FERC Account No. 226 – Unamortized Discount on Long Term Debt.

(ii) the preferred stock component, shall be the weighted cost to maturity of SDG&E's preferred stock and shall be computed as the ratio of the total cost recorded in FERC Account No. 437 - Dividends Declared –Preferred Stock, to the total Preferred Stock Issued as recorded in FERC Account No. 204.

(iii) the Return on Equity component, shall be as follows:

(a) Return on Equity shall equal ~~11.35~~XX.X%,

(b) Return on Equity shall be applied to proprietary capital as shown on page 112 of FERC Form 1, less FERC Account No. 204 – Preferred Stock Issued, found on line 3 of said page.

(b) Federal Income Tax shall equal

$$\frac{(A+[(C-B)/D])(FT)}{1 \cancel{-} – FT}$$

where:

FT is the Federal Income Tax Rate in effect on July 1 of each year;

A is the sum of the preferred stock component and the ~~r~~Return on ~~e~~Equity component, as determined in Sections II.A.2.a.(ii) and (iii) above;

B is Transmission Related Amortization of Investment Tax Credits and Transmission Related

Amortization of Excess Deferred Tax Liabilities, as determined in Sections I.B.57~~35~~ and I.B.56~~36~~ above;

C is the Equity AFUDC Component of Transmission Depreciation Expense and shall equal the amount of Transmission Depreciation Expense related to the Equity AFUDC Component of Transmission Plant; and

D is Transmission Rate Base, as determined in Section II.A.1, above.

(c) State Income Tax shall equal

$$\frac{(A+[(C-B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where:

ST is the State Income Tax Rate in effect on July 1 of each year;

A is the sum of the preferred stock component and Return on Equity component determined in Sections II.A.2.a.(ii) and (iii) above;

B is the Transmission Related Amortization of Investment Tax Credits and Transmission Related Amortization of Excess Deferred Tax Liabilities, as determined in Section I.B.57~~35~~ and I.B.56~~36~~, above;

C is the equity AFUDC Component of Transmission Depreciation Expense and shall equal the amount of Transmission Depreciation Expense related to the Equity AFUDC Component of Transmission Plant; and

D is the Transmission Rate Base, as determined in

Section II.A.1, above and Federal Income Tax is the rate determined in Section II.A.2.b above.

4. Incentive Cost of Capital Rate

The Incentive Cost of Capital Rate shall be defined the same as the Cost of Capital Rate, except that the Incentive Return on Equity rate shall be as defined in Section 1.B, Terms. In addition, Transmission Rate Base shall be as used in Section II.A. 2.

B. ~~End Use Customer~~ Base Transmission Revenue Requirement

~~End Use Customer~~ Base Transmission Revenue Requirement ("$BTRR_{EU}$") for a given Rate Effective Period shall be:

$BTRR_{EU} = PYRR_{EU} + FC_{EU}$ +/- True-Up Adjustment +/- Interest True-Up Adjustment

where~~:~~

$PYRR_{EU} = PYRR_{EU\text{-}NIR\ (non\text{-}\ incentive\ revenues)} + PYRR_{EU\text{-}IR\ (incentive\ revenues)}$

and where:

B.1 $PYRR_{EU\text{-}NIR}$ shall be determined on the basis of transmission cost data recorded in Form 1 and underlying ledger accounts for the prior year and such other costs and information provided in SDG&E's annual Informational Filing and shall be calculated as follows:

(A) Return and Associated Income Taxes, plus

(B) Transmission, General, ~~and~~ Common, and Electric Miscellaneous Intangible Plant Depreciation & Amortization Expense, plus

~~(C) Transmission Rrelated Electric Miscellaneous Intangible Plant Amortization Expense, plus~~

(D) Transmission Related Regulatory Debits, minus

(E) Transmission Related Amortization of Investment Tax Credits,

Minus

(F) Transmission Related Amortization of Excess Deferred Tax Liabilities, plus

(G) Transmission Related Payroll Taxes Expense, plus

(H) Transmission Related Property Taxes, plus

(I) Transmission Operation and Maintenance Expense, plus

(J) Transmission Related A&G Expenses, plus

(K) Valley Rainbow Project Costs Amortization Expense, plus

~~(K)~~(L) Transmission Related Abandoned ~~Cancelled~~ Project Cost Amortization Expense, minus

~~(L)~~(M) Transmission Related Revenue Credits, plus

~~(M)~~(N) Transmission Related Municipal Franchise Tax Expense, plus

~~(N)~~(O) Transmission Related Uncollectible Expense, plus

~~(O)~~(P) CPUC Intervenor Funding Expense, plus

~~(P)~~(Q) South Georgia Income Tax Adjustment, plus

(R) Gains and losses on Transmission Plant Held for Future Use.

B.2 $PYRR_{EU-IR}$ for Incentive Transmission Plant shall be determined from records maintained individually for each Incentive Project and shall be calculated as follows:

(A) Incentive Return and Associated Income Taxes applicable to Incentive Transmission Plant as defined in Section 1.B, Terms, plus

(B) Incentive Transmission Plant Depreciation Expense as defined in Section 1.B, Terms, plus

(C) Transmission Related Municipal Franchise Expense applicable to Incentive Transmission Plant, plus

(D) Transmission Related Uncollectible Expense applicable to Incentive Transmission Plant.

B.3 Forecast Period Capital Addition Revenue Requirements (“FC_{EU}”) shall be the product of Weighted Forecast Plant Additions and an Annual Fixed Charge Rate (“AFCR”).

B.~~2~~3.1 Forecast Period Capital Addition Revenue Requirements shall be calculated as follows:

FC_{EU} = Weighted Forecast Plant Additions excluding Transmission Plant Held for Future Use x $AFCR_{EU}$

where:

$AFCR_{EU}$ shall be the Annual Fixed Charge Rate for purposes of determining the amount of revenue requirements associated with Weighted Forecast Plant Additions to be included in the determination of $BTRR_{EU}$, and is calculated as follows:

$AFCR_{EU}$ = $PYRR_{EU}$ minus the South Georgia Income Tax Adjustment plus Transmission Related Amortization of Investment Tax Credit, plus Transmission Related Amortization of Excess Deferred Tax Liability, minus Valley Rainbow Project Cost Amortization Expense, plus CPUC Intervenor Funding Expenses, plus (Gains)/Losses from Sale of Plant Held for Future Use divided by the sum of Transmission Plant, Transmission Related General Plant, ~~and~~ Transmission Related Common Plant and Transmission Related Electric Miscellaneous Intangible Plant balances (which said balances, in each instance, shall be calculated in accordance with 18 CFR Section 35.13).

B.~~2~~3.1.1 Revenue requirements for Transmission Plant Held for Future Use during the Forecast Period shall be determined by multiplying the Cost of Capital Rate by Forecast Period Transmission Plant Held for Future Use using the same weighting method that is used for determining the revenue requirements for Weighted Forecast Plant Additions. In addition, Transmission Rate Base, as used in II.A.1~~2.(b) D~~, shall be changed to weighted Transmission Plant Held for Future Use.

B. 3. 2 Forecast Period Capital Addition Incentive Revenue Requirements for Incentive Projects that receive an Incentive Return on Equity shall be calculated as follows:

$FC_{EU\text{-}IR}$ = Weighted Forecast Plant Additions x $AFCR_{EU\text{-}IR\text{-}ROE}$

where:

$AFCR_{EU\text{-}IR\text{-}ROE}$ shall be calculated using the methodology in II.B.3.1 above, using Transmission Plant as if it were Incentive Transmission Plant and using the Cost of Capital Rate.

B.3.3 Forecast Transmission Incentive CWIP Revenues

The Forecast Transmission Incentive CWIP Revenues to be included in the derivation of the Retail and Wholesale BTRR shall be calculated by multiplying the Cost of Capital Rate by the 13-month weighted average incremental CWIP balance during the Rate Effective Period. The incremental CWIP balance shall be equal to the difference in the CWIP balance at the end of the month in the Forecast Period just prior to the first month of the Rate Effect Period, less the CWIP balance at the end of the Base Period. This difference shall be added to the monthly CWIP expenditures during the Rate Effective Period until the Incentive Project goes into service. The Cost of Capital Rate shall be equal to that used in the Base Period.

B.4 True-Up Adjustment shall be calculated in accordance with Section II.D below.

B.5 Interest True-Up Adjustment shall be calculated in accordance with Section II. E below.

C. CAISO Base Transmission Revenue Requirement

C.1 CAISO Base Transmission Revenue Requirement (“$BTRR_{CAISO}$”) for a given Rate Effective Period shall equal ~~be~~:

~~$BTRR_{ISO}$ = $PYRR_{ISO}$ + FC_{ISO} +/- True-Up Adjustment~~

~~where~~:

$BTRR_{EU,}$ plus CPUC Intervenor Funding Expense, minus South Georgia Income Tax Adjustment, minus Transmission Related Amortization of Excess Deferred tax Liabilities.

C.1 ~~$PYRR_{ISO}$ for $BTRR_{ISO}$, shall be determined on the basis of~~

~~transmission cost data recorded in Form 1 and underlying ledger accounts for the prior year and such other costs and information provided in SDG&E's annual Informational Filing and shall be calculated as follows:~~

~~(A) Return and Associated Income Taxes, plus~~

~~(B) Transmission, General, and Common Plant Depreciation Expense, plus~~

~~(C) Transmission Related Electric Miscellaneous Intangible Plant Amortization Expense , plus~~

~~(D) Transmission Related Regulatory Debits, minus~~

~~(E) Transmission Related Amortization of Investment Tax Credits, minus~~

~~(F) Transmission Related Amortization of Excess Deferred Tax Liabilities, plus~~

~~(G) Transmission Related Payroll Taxes Expense, plus~~

~~(H) Transmission Related Property Taxes, plus~~

~~(I) Transmission Operation and Maintenance Expense, plus~~

~~(J) Transmission Related A&G Expenses, plus~~

~~(K) Valley Rainbow Project Costs and Transmission Related Cancelled Project Cost, minus~~

~~(L) Transmission Related Revenue Credits, plus~~

~~(M) Transmission Related Municipal Franchise Tax Expense.~~

~~(N) Gains and losses on Transmission Plant Held for Future Use~~

~~C.32 Forecast Period Capital Addition Revenue Requirements ("FC_{ISO}") shall be the product of Weighted Forecast Plant Additions and an Annual Fixed Charge Rate ("AFCR").~~

C.3~~2~~.1 ~~Forecast Period Capital Addition Revenue Requirements shall be calculated as follows:~~

~~FC_{ISO} = Weighted Forecast Plant Additions excluding Transmission Plant Held for Future Use x $AFCR_{ISO}$~~

~~where:~~

~~$AFCR_{ISO}$ shall be the Annual Fixed Charge Rate for purposes of determining $BTRR_{ISO}$ used to calculate High Voltage and Low Voltage Access Charges and shall be calculated as follows:~~

~~$AFCR_{ISO}$ = $PYRR_{ISO}$ plus Transmission Related Amortization of Investment Tax Credits, plus Transmission Related Amortization of Excess Deferred Tax Liabilities, minus Valley Rainbow Project Costs and any Transmission Related Cancelled Project Cost that the Commission determines shall be amortized as an expense, divided by the sum of Transmission Plant, plus Transmission Related General Plant, plus Transmission Related Common Plant, plus Transmission Related Electric Miscellaneous Intangible Plant balances (which balances, in each instance, shall be calculated in accordance with 18 CFR Section 35.13).~~

~~C.2.1 .1 Revenue requirements for Transmission Plant Held for Future Use during the Forecast Period shall be determined by multiplying the Cost of Capital Rate by Forecast Period Transmission Plant Held for Future Use using the same weighting method that is used for determining the revenue requirements for Weighted Forecast Plant Additions. In addition, Transmission Rate Base, as used in II.A.2. (b) D, shall be changed to weighted Transmission Plant Held for Future Use.~~

C.2 ~~3~~. $BTTR_{CAISO}$ shall be further allocated between HV Transmission Facility revenue requirements ("$BTTR_{CAISO-HV}$") and LV Transmission Facility revenue requirements ("$BTTR_{CAISO-LV}$") as set forth in Appendix IX ~~follows:~~

~~i. $BTRR_{ISO-HV}$ = $BTRR_{ISO}$ multiplied by the allocation factors applicable to HV Transmission Facilities as described in the Section 1.A.Existing and New HV and LV Allocation Factors~~

~~ii. $BTRR_{ISO-LV}$ = $BTRR_{ISO}$ multiplied by the allocation factors applicable to LV Transmission Facilities as described in the Section 1.A. Existing and New HV and LV Allocation Factors.~~

~~C. 4 True-Up Adjustment shall be calculated in accordance with Section II.D below.~~

~~C.5 Interest True-Up Adjustment shall be calculated in accordance with Section II. E below.~~

D. True-Up Adjustment shall be calculated as follows:

1. Derivation of True-Up Adjustment:

SDG&E will derive ~~two~~ the True-Up Adjustment~~s~~ as follows. Please note that the $BTRR_{eu}$ True-Up Adjustment is also applicable to the $BTRR_{CAISO}$ ~~one applicable to End Use Customers ("TUA_{EU}") and one applicable to ISO wholesale customers ("TUA_{ISO}"). Such True-Up Adjustments shall equal the following:~~

A. The Derivation of End-Use ~~Retail~~ True-Up Adjustment shall be calculated as follows:

The sum of monthly revenues ("TUR") recorded during the True-Up

Period minus the sum of monthly true-up cost of service ("TUCS") during the True-Up Period.

Such True-Up Adjustments shall be calculated for each month of the True-Up Period and adjusted for Interest as described below.

B. ~~2.~~ Derivation of the End-Use True-Up Cost of Service applicable to the True-Up Period:

In order to derive the End Use True-Up Cost of Service ("$TUCS_{EU}$") ~~and Wholesale True-Up Cost of Service ("$TUCS_{ISO}$")~~ for any True-Up Period, SDG&E shall determine its cost of providing transmission service for that True-Up Period using the cost of service methodology described in Sections II.B ~~and II.C~~ of this Appendix VIII, and shall distribute that $TUCS_{EU}$ ~~and $TUCS_{ISO}$ respectively~~, to each month of the True-Up Period by stating its True-Up Cost of Service on an average annual rate and multiplying said annual average rate times the actual recorded monthly determinants for each month of the True-Up Period, as more fully described below.

Pursuant to the methodology set forth in Appendix IX, SDG&E shall compute the following to derive the $TUCS_{EU}$ ~~and the $TUCS_{ISO}$:~~

The $TUCS_{EU}$ for each month of the True-Up Period for each class of service specified in Appendix IX of SDG&E's Transmission Owner Tariff shall be calculated by dividing the $TUCS_{EU}$ for the True-Up Period by the annual billing determinants for that customer class and multiplying the resulting amount by the recorded monthly billing determinants for that customer class for that month.

~~a. The $TUCS_{ISO}$ for each month of the True-Up Period for each class of service specified in Appendix IX of SDG&E's Transmission Owner Tariff shall be calculated by dividing the~~

~~TUCS$_{ISO}$ for the True-Up Period by the annual billing determinants, as measured at transmission voltage level, for that customer class and multiplying the resulting amount by the recorded monthly billing determinants, as measured at transmission voltage level, for that customer class for that month.~~

2 ~~3~~. Derivation of End Use True-Up Revenues during the True-Up Period: SDG&E shall determine for each month of the True-Up Period the following; ~~:~~

a. True-Up Revenues for the End Use Customers ("TUR$_{EU}$") shall equal the total End Use ~~Base~~ ~~t~~Transmission ~~Revenue Requirement~~ revenues SDG&E recorded for each month of the True-Up Period as received from End Use Customers, minus the True-Up Adjustment and Interest True-Up Adjustment embedded in those recorded revenues. To the extent the True-Up Adjustment and the Interest True-Up Adjustment balances are not fully amortized at the end of the Rate Effective Period, SDG&E will recalculate the amortization rate to achieve a zero balance in the last month of the Rate Effective Period.

~~b. True-Up Revenues for ISO wholesale customers ("TUR$_{ISO}$") shall equal the following:~~

~~1. for the first five months of the True-Up Period (April through August) the ISO True-Up revenues will equal for each class of service as specified in Appendix IX of SDG&E's Transmission Owner's Tariff, true-up transmission rates in effect during this period multiplied by the End Use Customer recorded billing determinants, as measured at transmission voltage level for each month of this period. The true-up transmission rates by the class of service will equal the BTRR$_{ISO}$ in effect during this period allocated (using the class allocation factor as described in~~

~~Appendix IX) to each class of service, divided by the class of service billing determinants applicable to this BTRR$_{ISO}$.~~

2. ~~for the last seven months of the True-Up Period (September through March) the ISO true-up revenues will equal for each class of service as specified in Appendix IX of SDG&E's Transmission Owner's Tariff, true-up transmission rates in effect during this period multiplied by the End Use Customer recorded billing determinants, as measured at the transmission voltage level, for each month of this period. The true-up transmission rates by class of service will equal the BTRR$_{ISO}$ in effect during this period allocated (using the class allocation factor as described in Appendix IX) to each class of service, divided by the class of service billing determinants applicable to this BTRR$_{ISO}$.~~

~~4.~~ 3. Derivation of Interest Related to Over and Under Recovery of Costs:

For each month of the True-Up Period, for any over- or under- recovery of its costs as determined by comparing TUCS and TUR, SDG&E shall calculate an applicable amount of Interest pursuant to 18 CFR Section 35.1 9a.

E. Interest True-Up Adjustment Calculation

a. The Interest True-Up adjustment for any formula cycle filing shall be calculated for the current cycle True-Up Period in two parts. First, for the current cycle filing, SDG&E shall take the previous cycle True-Up Adjustment overcollection (undercollection) balance and calculate the interest that accrues on this balance for the ~~first five eight~~ 12 months of the current True-Up Adjustment Period (January ~~April~~ 1 through December ~~August~~t 31). SDG&E shall calculate the interest amount pursuant to 18 CFR Section 35.19, by compounding the related interest on a quarterly basis.

b. Second, interest shall be calculated monthly on the unamortized overcollection (undercollection) balance of the sum of the interest that occurred in the ~~first~~ 12 ~~five~~ months as calculated in (a) above ~~plus the previous cycle True-Up Adjustment balance~~. ~~The monthly amortized balance will be calculated for the remaining period from September 1 to~~ ~~March August~~ December ~~31 of the current cycle Rate Effective Period~~. The monthly amount by which the balance decreases will be calculated by multiplying an amortization rate per kWh times each month's retail sales in kWhs. The amortization rate per kWh will be calculated by taking the beginning overcollection/(undercollection) balance as of the start of the rate effective period and dividing it by the kWhs in the current Rate Effective Period. ~~The kWhs in the Rate Effective Period shall equal the first eight seven months actual and the last four five month forecast~~.

c. The interest in parts (a) and (b) above for an overcollection (undercollection) balance shall be summed and credited to the current cycle formula True-Up Adjustment. In the event interest is determined on an undercollection balance in part (a) and (b) above, such interest shall be added to the current cycle True-Up Adjustment.

d. The unamortized Interest True-Up Adjustment balance from the current Interest True-Up Adjustment (balance as of December ~~March~~ 31) will be carried forward to the following cyclic filing and used as the beginning monthly unamortized balance beginning the first month of the True-Up Adjustment Process (January ~~April~~). This unamortized balance shall be amortized over the remaining months of the current cycle Rate Effective Period months (January ~~April~~ through December ~~August~~). Monthly interest on the unamortized balance for these months will then be calculated. This interest will then be added to the interest calculated as part of the following cycle's True-Up Adjustment.

In the following cycle filing, the process described in items (a) through (c) shall be repeated including the calculation of interest described in item (d) above. ~~Note should be made that in the following cyclic filing's Interest True-Up Adjustment process the interest calculations described in items (c) and (d) will overlap for the first five months of the Interest True-Up calculation process (April through August).~~

TO4 Formula - Appendix VIII Modifications

Non Substantive Changes - Definition Changes and or Addition of Definitions for Clarification Purposes

	1	2	3	4	
Line No	Definitions	SDG 3-1 Page No.	Does it Affect Revenues	Comments	Line No
1	Annual Fixed Charged Rate	11	N	definition revised to show where the AFCR is developed	1
2	Base Period	11	N	Revision made to reference TO4 initial base period.	2
3	CAISO Base Transmission Revenue Requirements	11	N	Added definition	3
4	CPUC Intervenor Funding Expense	11	N	Revision due to the removal of the $700 CPUC Intervenor Expense associated with Valley Rainbow Project	4
5	End Use Customer Base Transmission Revenue Requirements	13	N	Added definition	5
6	Forecast Period	13	N	Revised to reflect TO4 Cycle specific Forecast Periods	6
7	High Voltage and Low Voltage Allocation Factor	7	N	Deleted terms "Existing" and "New" because it is no longer used in Tariff.	7
8	Rate Effective Period	16	N	Added definition	8
9	Return on Equity	16	N	Added definition	9
10	Transmission General, Com, and Misc. Intangible Plt Deprec. Exp.	17	N	Revised definition to reflect calculation	10
11	Transmission Operations and Maintenance Expense	17	N	Revised to specify applicable FERC accounts in Transmission O&M and update Reliability Service charge types	11
12	Transmission Related Abandoned Project Costs	20	N	Changed from "Cancelled" to "Abandoned" to reflect Order No. 679	12
13	Transmission Related Abandoned Project Cost Amortization Expense	20	N	Changed from "Cancelled" to "Abandoned" to reflect Order No. 679	13
14	Transmission Related Accumulated Deferred Income Taxes	20	N	Developed new single definition to reconcile 3 separate terms used in Section II as reflected in Statement BK1	14
15	Transmission Related A&G Expenses	21	N	Revised to reflect timing of TO4 Formula	15
16	Transmission Related Cash Working Capital	22	N	Moved definition from Section II to Section I.	16
17	Transmission Related Common Plant	23	N	Moved definition from Section II to Section 1	17
18	Transmission Related Common Plant Depreciation Expense	23	N	Added definition for clarification purposes	18
19	Transmission Related Common Plant Depreciation Reserve	23	N	Added definition for clarification purposes	19
20	Transmission Related Depreciation Reserve	23	N	Moved definition from Section II to Section 1 and revised intangible plant	20
21	Transmission Related General Plant	23	N	Moved definition from Section II to Section 1	21
22	Transmission Related General Plant Depreciation Expense	23	N	Added definition	22
23	Transmission Related Electric Gen and Cmn Plant Accum Def Inc. Taxes	24	N	Moved definition from Section II to Section 1	23
24	Transmission Related General Plant Depreciation Reserve	24	N	Added	24

TO4 Formula - Appendix VIII Modifications					
Non Substantive Changes - Definition Changes and or Addition of Definitions for Clarification Purposes					
	1	**2**	**3**	**4**	
Line No	Definitions	SDG 3-1 Page No.	Does it Affect Revenues	Comments	Line No
25	Transmission Related Materials and Supplies	25	N	Moved definition from Section II to Section 1	25
26	Transmission Related Prepayments	26	N	Moved definition from Section II to Section 1	26
27	Valley Rainbow Project Cost	27	N	Revised to reflect end date of September 2013.	27
28	**Other Modifications**				28
29	Section C - CAISO Base Transmission Revenue Requirement	44-47	N	Simplified formula language by eliminating redundant calculation by applying Retail BTRR to Wholesale BTRR	29
30	Section D - True-Up Adjustment Calculation	47-50	N	Simplified formula language by eliminating redundant calculation by applying Retail BTRR to Wholesale BTRR	30
31	Section E - Interest True-Up Adjustment Calculation	50-52	N	Revised Section E - to reflect TU Period is a calandar year.	31

TO4 Formula - Appendix VIII Modifications
FERC Order No. 679 and Others
Substantive Changes to TO3 Appendix VIII to be Used in TO4

Line No	1 Definitions	2 SDG 3-1 Page No.	3 Does it Affect Revenues	4 Comments	Line No
	FERC Order No. 679 Modifications				
1	Incentive	13	Y	Term added to reflect inclusion of specific Order No. 679 incentives	1
2	Incentive Abandoned Project Cost	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	2
3	Incentive CWIP	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	3
4	Incentive Project	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	4
5	Incentive Return and Associated Income Taxes	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	5
6	Incentive Return on Equity	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	6
7	Incentive Transmission Plant	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	7
8	Incentive Transmission Plant Accumulated Deferred Income Taxes	14	Y	Term added to reflect inclusion of specific Order No. 679 incentives	8
9	Incentive Transmission Plant Depreciation Expense	15	Y	Term added to reflect inclusion of specific Order No. 679 incentives	9
10	Incentive Transmission Plant Depreciation Reserves	15	Y	Term added to reflect inclusion of specific Order No. 679 incentives	10
11	Incentive Transmission Plant Other Regulatory Assets/Liabilities	15	Y	Term added to reflect inclusion of specific Order No. 679 incentives	11
12	Incentive Weighted Forecast Plant Additions	15	Y	Term added to reflect inclusion of specific Order No. 679 incentives	12
13					13
14	**Other Substantive Changes -Miscellaneous**				14
15	Administrative and General Expenses - Electric	10	Y	Revised definition to permit allocation and direct assignment consistent with cost causation principles.	15
16	South Georgia Income Tax Adjustment	17	Y	Revised Tax Adjustment from stated amount to amount referenced in FERC Form 1.	16
17	Transmission Related Amortization of Investment Tax Credits	22	Y	Revised Amortization Investment Tax Credit from stated amount to amount referenced in FERC Form 1.	17
18	Transmission Plant Depreciation Expense	19	Y	Transmission depreciations rates are being updated due to new depreciation study.	18
19	Transmission Related Electric Miscellaneous Intangible Plant	24	Y	Moved and revised definition to permit allocation and direct assignment consistent with cost causation principles.	19
20	Transmission Related Elec. Misc. Intangible Plt Accum. Def. Inc.Taxes	25	Y	same as line 19 above	20
21	Transmission Related Elec. Miscellaneous Intangible Plant Amortization Expense	25	Y	same as line 19 above	21
22	Transmission Related Elec. Miscellaneous Intangible Plant Amortization Reserve	25	Y	same as line 19 above	22
23	Transmission Related Municipal Franchise Tax Expense	25	Y	Franchise Tax Rate updated to reflect current rate subject to change pending approval of 2012 GRC Filing.	23
24	Transmission Related Uncollectible Expense	27	Y	Uncollectible Rate updated to reflect current rate subject to change pending approval of 2012 GRC Filing.	24
25	True-Up Period	27	Y	True-Up Period changed to calendar year (12 months ended December 31st) - the same time period as the Base Period.	25

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. Revenues:**			1
2	Transmission Operation & Maintenance Expense	$ 51,765	Statement AH; Page 5, Line 8	2
3				3
4	Transmission Related A&G Expenses	42,175	Statement AH; Page 5, Line 57	4
5				5
6	CPUC Intervenor Funding Expense	-	Statement AH; Page 5, Line 9	6
7				7
8	Total O&M Expenses	$ 93,940	Sum Lines 2 thru 6	8
9				9
10	Transmission, Intangible, General and Common Depr. & Amort. Expense	54,756	Statement AJ; Page 7, Line 19	10
11				11
12	Valley Rainbow Project Cost Amortization Expense	1,893	Statement AJ; Page 7, Line 23	12
13				13
14	Transmission Abandoned Project Cost Amortization Expense	-	Statement AJ; Page 7, Line 25	14
15				15
16	Transmission Related Property Taxes Expense	11,156	Statement AK; Page 8, Line 27	16
17				17
18	Transmission Related Payroll Taxes Expense	2,030	Statement AK; Page 8, Line 34	18
19				19
20	Sub-Total Expense	$ 163,775	Sum Lines 8 thru 18	20
21				21
22	Cost of Capital Rate $_{(COCR)}$	11.8690%	Statement AV; Page 14, Line 33	22
23				23
24	Transmission Rate Base	$ 1,219,088	Statement BK-1; Page 2, Line 26	24
25				25
26	Return and Associated Income Taxes	$ 144,694	Line 22 x Line 24	26
27				27
28	South Georgia Income Tax Adjustment	2,333	Statement AQ; Page 10, Line 1	28
29	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11, Line 1	29
30	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement AR; Page 11, Line 3	30
31	Transmission Related Revenue Credits	(2,652)	Statement AU; Page 12, Line 11	31
32	Transmission Related Regulatory Debits	-	Not Applicable in TO4-Cycle 1	32
33	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement AU; Page 12, Line 13	33
34				34
35	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$ 307,885	Line 20 + Sum Lines (26 thru 33)	35
36				36
37	**B. Incentive Revenues:**			37
38	Incentive Transmission Plant Depreciation Expense	$ -	Statement AJ; Page 7; Line 21	38
39	Sub-Total Expense	$ -	Sum Lines 38	39
40				40
41	Incentive Cost of Capital Rate $_{(ICOCR)}$	0.0000%	Statement AV; Page 15; Line 33	41
42	Incentive Transmission Rate Base	$ -	Statement BK-1; Page 2; Line 39	42
43				43
44	Incentive Return and Associated Income Taxes	$ -	Line 41 x Line 42	44
45				45
46	Incentive End of Prior Year Revenues (PYRR $_{EU-IR}$) Excluding FF&U	$ -	Sum Lines 39; 44	46
47				47
48	**C. Total (PYRR $_{EU}$) Excluding FF&U [1]**	$ 307,885	Sum Lines 35; 46	48

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for 12 months ending May 31, 2012.

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Rate Base			
1	Net Transmission Plant:			1
2	Transmission Plant	$ 1,256,940	Statement BK-1; Page 3; Line 16	2
3	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Statement BK-1; Page 3; Line 17	3
4	Transmission Related General Plant	16,585	Statement BK-1; Page 3; Line 18	4
5	Transmission Related Common Plant	32,956	Statement BK-1; Page 3; Line 19	5
6	Total Net Transmission Plant	$ 1,307,515	Sum Lines 2 thru 5	6
7				7
8	Rate Base Additions:			8
9	Transmission Plant Held for Future Use	$ 66,487	Statement AG; Page 4; Line 3	9
10	Transmission Abandoned Project Cost	-	Not Applicable in TO4-Cycle 1	10
11	Total Rate Base Additions	$ 66,487	Sum Lines 9 thru 10	11
12				12
13	Rate Base Reductions:			13
14	Transmission Related Accum. Def. Inc. Taxes	$ (184,167)	Statement AF; Page 3; Line 5	14
15	Transmission Related Abandoned Accum. Def. Inc. Taxes	-	Not Applicable in TO4-Cycle 1	15
16	Total Rate Base Reductions	$ (184,167)	Sum Lines 14 thru 15	16
17				17
18	Working Capital:			18
19	Transmission Related Material and Supplies	$ 11,278	Statement AL; Page 9; Line 5	19
20	Transmission Related Prepayments	6,232	Statement AL; Page 9; Line 9	20
21	Transmission Related Cash Working Capital	11,743	Statement AL; Page 9; Line 19	21
22	Total Working Capital	$ 29,253	Sum Lines 19 thru 21	22
23				23
24	Other Regulatory Assets/Liabilities	-	Not Applicable in TO4-Cycle 1	24
25				25
26	Total Transmission Rate Base	$ 1,219,088	Sum Lines 6; 11; 16; 22; 24	26
27				27
28	**B. Incentive Transmission Rate Base**			28
29	Net Incentive Transmission Plant	$ -	Statement BK-1; Page 3; Line 25	29
30				30
31	Rate Base Addition:			31
32	Transmission Construction Work In Progress for Incentive Projects	$ -	Not Applicable in TO4-Cycle 1	32
33	Total Rate Base Addition	$ -	Sum Line 32	33
34				34
35	Rate Base Reduction:			35
36	Incentive Transmission Plant Related Accum. Def. Income Taxes	$ -	Statement AF; Page 3; Line 7	36
37	Total Rate Base Reduction	$ -	Sum Line 36	37
38				38
39	Total Incentive Transmission Rate Base	$ -	Sum Lines 29; 33; 37	39

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Plant			
1	Gross Transmission Plant:			1
2	Transmission Plant	$ 1,785,708	Statement AD; Page 1, Line 31	2
3	Transmission Related Electric Miscellaneous Intangible Plant	5,982	Statement AD; Page 1, Line 29	3
4	Transmission Related General Plant	29,185	Statement AD; Page 1, Line 33	4
5	Transmission Related Common Plant	67,986	Statement AD; Page 1, Line 35	5
6	Total Gross Transmission Plant	$ 1,888,861	Sum Lines 2 thru 5	6
7				7
8	Accumulated Depreciation Reserve:			8
9	Transmission Plant Depreciation Reserve	$ 528,768	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Miscellaneous Intangible Amortization Reserve	4,948	Statement AE; Page 2, Line 7	10
11	Transmission Related General Plant Depr Reserve	12,600	Statement AE; Page 2, Line 15	11
12	Transmission Related Common Plant Depr Reserve	35,030	Statement AE; Page 2, Line 17	12
13	Total Transmission Related Accumulated Depreciation Reserve	$ 581,346	Sum Lines 9 thru 12	13
14				14
15	Net Transmission Plant:			15
16	Transmission Plant	$ 1,256,940	Line 2 Minus Line 9	16
17	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Line 3 Minus Line 10	17
18	Transmission Related General Plant	16,585	Line 4 Minus Line 11	18
19	Transmission Related Common Plant	32,956	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	$ 1,307,515	Sum Lines 16 thru 19	20
21				21
22	**B. Incentive Transmission Plant**			22
23	Incentive Transmission Plant	$ -	Statement AD; Page 1, Line 17	23
24	Incentive Transmission Related Accumulated Depreciation Reserve	-	Statement AE; Page 2, Line 3	24
25	Total Net Incentive Transmission Plant	$ -	Line 23 Minus Line 24	25

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC $_{EU}$)
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate (AFCR $_{EU}$) Applicable to**			1
2	**Weighted Forecast Plant Additions:**			2
3	PYRR $_{EU}$ Excluding Franchise Fees and Uncollectible	$ 307,885	Statement BK-1; Page 1; Line 35	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement BK-1; Page 1; Line 33	9
10	Total (PYRR EU) Excluding FF&U - Adjusted	$ 303,924	Sum Lines 3 thru 9	10
11				11
12	Gross Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	12
13				13
14	Annual Fix Charge Rate (AFCR $_{EU}$)	16.0903%	Line 10 / Line 12	14
15				15
16	Weighted Forecast Plant Additions	$ 2,135,619	Summary of HV-LV Plant Additions; Pg 1; Ln 6	16
17				17
18	Forecast Period Capital Addition Revenue Requirements	$ 343,628	Line 14 x Line 16	18
19				19
20	**B. Derivation of Revenue Requirements for Transmission Plant Held for**			20
21	**Future Use During the Forecast Period**			21
22	Forecast Period Transmission Plant Held for Future Use	$ -	Not Applicable in TO4-Cycle 1	22
23				23
24	Cost of Capital Rate $_{(COCR)}$	0.0000%	Not Applicable in TO4-Cycle 1	24
25				25
26	Revenue Requirements for Transmission Plant Held for Future Use	$ -	Line 22 x Line 24	26

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC_{EU})
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO INCENTIVE CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate ($AFCR_{EU\text{-}IR\text{-}ROE}$) Applicable to**			1
2	**Incentive Weighted Forecast Plant Additions (ROE Incentive Only):**			2
3	$PYRR_{EU\text{-}IR\text{-}ROE}$ Excluding Franchise Fees and Uncollectible	$ -	Not Applicable in TO4-Cycle 1	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	Total ($PYRR_{EU}$) Excluding FF&U - Adjusted	$ (3,961)	Sum Lines 3 thru 8	9
10				10
11	Gross Electric Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	11
12				12
13	Annual Fix Charge Rate ($AFCR_{EU\text{-}IR\text{-}ROE}$)	0.0000%	Not Applicable in TO4-Cycle 1	13
14				14
15	Incentive Weighted Forecast Plant Additions	$ -	Not Applicable in TO4-Cycle 1	15
16				16
17	Forecast Period Incentive Capital Additions Revenues ($FC_{EU\text{-}IR\text{-}ROE}$)	$ -	Line 13 x Line 15	17
18				18
19	**B. Derivation of Transmission CWIP Incentive Projects Revenue Requirements:**			19
20	Transmission Construction Work In Progress Incentive Projects	$ -	Not Applicable in TO4-Cycle 1	20
21				21
22	Cost of Capital Rate $_{(COCR)}$	0.0000%	Not Applicable in TO4-Cycle 1	22
23				23
24	Transmission CWIP Incentive Projects Revenue Requirements	$ -	Line 20 x Line 22	24

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Base Transmission Revenue Requirements (BTRR $_{EU}$)
For the Rate Effective Period September 1, 2013 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. End Use Customer Base Transmission Revenue Requirement (BTRR $_{EU}$):**			1
2				2
3	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$ 307,885	Statement BK-1; Page 1; Line 35	3
4				4
5	Incentive End of Prior Year Revenues (PYRR $_{EU-IR}$) Excluding FF&U	-	Statement BK-1; Page 1; Line 46	5
6				6
7	Sub-Total Base Period Revenues	$ 307,885	Sum Lines 3 thru 5	7
8				8
9	True-Up Period Adjustment	$ -	Not Applicable in TO4-Cycle 1	9
10				10
11	Interest True-Up Adjustment	-	Not Applicable in TO4-Cycle 1	11
12				12
13	Sub-Total True-Up Adjustments	$ -	Sum Lines 9 thru 11	13
14				14
15	**B. Annual Fixed Charges Applicable to Capital Projects:**			15
16				16
17	Forecast Period Capital Addition Revenue Requirements	$ 343,628	Statement BK-1; Page 4, Line 18	17
18				18
19	Revenue Requirements for Transmission Plant Held for Future Use	-	Statement BK-1; Page 4, Line 26	19
20				20
21	Sub-Total Revenue Requirements for Capital Projects	$ 343,628	Sum Lines 17 thru 19	21
22				22
23	**C. Incentive Transmission CWIP Revenue Requirements**			23
24				24
25	Transmission CWIP Incentive Projects Revenue Requirements	$ -	Statement BK-1; Page 5, Line 24	25
26				26
27	**D. Annual Fixed Charges Applicable to Incentive Capital Projects:**			27
28				28
29	Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-ROE}$)	$ -	Statement BK-1; Page 5, Line 17	29
30				30
31	**E. Subtotal BTRR $_{EU}$ Excluding FF&U:**	$ 651,513	Sum Lines 7; 13; 21; 25; 29	31
32				32
33	Transmission Related Municipal Franchise Fees Expenses	6,694	Line 31 x 1.0275%	33
34	Transmission Related Uncollectible Expense	919	Line 31 x 0.141%	34
35				35
36	**F. Total Retail BTRR $_{EU}$ With FF&U:**	$ 659,126	Sum Lines 31 thru 34	36

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Leonor Sanchez, being duly sworn, on oath, says that she is the Leonor Sanchez identified in the foregoing prepared direct testimony; that she prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers would, under oath, be the same.

Leonor Sanchez
Leonor Sanchez

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, ANNIE VICTORIA RUIZ, a Notary Public, personally appeared Leonor Sanchez, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that she executed the same in her authorized capacity, and that by her signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ANNIE VICTORIA RUIZ
COMM. #1877490
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2014

Annie Victoria Ruiz

Exhibit No. SDG-4

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF

LOLIT TANEDO

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

EXHIBIT NO. SDG-4

#275111

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	**)**	**Docket No. ER13-___-000**

PREPARED DIRECT TESTIMONY OF
LOLIT TANEDO
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name and business address?

A1. My name is Lolit Tanedo. My business address is 8315 Century Park Court – CP21C, San Diego, California, 92123-1548.

Q2. By whom are you employed and in what capacity?

A2. I am employed by San Diego Gas & Electric Company (SDG&E) as a Senior Business Analyst in the Transmission Revenue and Budgeting group. My responsibilities include assisting in developing and analyzing transmission revenue requirements.

Q3. Please briefly describe your educational and professional background.

A3. I received a Bachelor of Science major in Accounting from Jose Rizal University in Manila, Philippines. I am a Certified Public Accountant in the Philippines and in California. I am also a member of the American Institute of Certified Public Accountants. I have been employed by SDG&E since January 1996 in various positions, and assumed the position of Senior Business Analyst in August 2009 in the Transmission Revenue and Budgeting group. In this position, I am involved with the overall determination of transmission revenue requirements and rate design for transmission rates.

Q4. Have you submitted testimony before the Federal Energy Regulatory Commission (Commission or FERC) in the past?

A4. No.

II. PURPOSE OF TESTIMONY

Q5. What is the purpose of your testimony?

A5. The main purpose of my testimony is to describe and quantify how the Transmission Owner (TO) Formula's (TO4) End Use or retail Prior Year Revenue Requirements (PYRR) (Base Period) in Statement BK-1 will be derived pursuant to Appendix VIII. Appendix VIII is described in detail in the testimony of Leonor Sanchez (Exhibit No. SDG-3). For this quantification, SDG&E is using for the initial TO4 Cycle 1 filing, a Base Period equal to 12-months ended May 31, 2012. Thereafter, Base Period for all subsequent cycles in TO4 will be equal to a calendar year. Additionally, in my testimony I will describe how SDG&E will develop other aspects of its retail Base Transmission Revenue Requirements (BTRR), which include its proposed True Up Adjustment; Interest True Up Adjustment; and Forecast Period revenues. These other aspects are discussed in more detail in the testimony of Raulin Farinas.

Q6. How is your testimony organized?

A6. To quantify the Base Period revenues as well as the other aspects as discussed above, my testimony is organized as follows:

- I. Introduction
- II. Purpose
- III. Cost Statements used to derive Base Period revenues
- IV. Derivation of transmission plant and other plant items allocated to transmission:
  - A. Derivation of Transmission plant balance
  - B. Per Book Transmission adjusted for ratemaking for FERC Seven Factor Definition of Transmission (Transmission Ratemaking Balances)
  - C. Derivation of Other Statement AD Plant Balances to develop Transmission Plant Allocation Factor
  - D. Allocation of common plant to the Electric Division and subsequently to transmission service
  - E. Allocation of electric general plant to transmission service
  - F. Derivation of Transmission Plant Allocation factor
- V. Derivation of Transmission Accumulated Depreciation Reserve
- VI. Derivation of Accumulated Deferred Income Taxes

VII. Derivation of Working Capital
VII. Derivation of Transmission Rate Base
IX. Derivation of Transmission O&M Expenses
X. Derivation of A&G expenses Allocated to Transmission Service
XI. Derivation of Transmission Depreciation Expense
XII. Transmission Abandoned Project Cost Amortization Expense
XIII. Transmission Related Property Taxes and Other Taxes other than Income Taxes
IXV. Derivation of Other Taxes other than Income Taxes Allocated to Transmission
XV. Derivation of Revenue Credits
XVI. Derivation of Transmission Wages and Salaries Allocation Factor
XVII. Derivation of Cost of Capital and Income Taxes Related with Cost of Capital
XVII. Derivation of End Use BTRR for the Initial Base Period Including Forecast Period and TU Adjustment Revenue Components
XIX. Cost Statements I am sponsoring

III. COST STATEMENTS USED TO DERIVE BASE PERIOD REVENUES

Q7. Please explain the cost statements (*e.g.*, Statements AD, AE, AJ) that will be used in TO4 to derive SDG&E's BTRR.

A7. The statements that will be used are very similar to what SDG&E used in its TO3 Formula filings. I have labeled these cost statements consistently with the labeling provided by Section 35.13 of the Commission's regulations. For example, all plant balances will be shown in Statement AD, all O&M expenses will be shown in Statement AH, and so on. This labeling procedure will assist parties in following the logic and flow of the formula. In this TO4 filing, these statements are provided in Volume 4.

Additionally, as part of SDG&E's proposed TO4 formula process, workpapers will also be provided that support each cost statement as needed. In the instant filing, Volume 5 contains these work papers. All cost statements will be described in more detail below.

Q8. Does SDG&E's Base Period reflect actual recorded costs?

A8. Yes, with a few exceptions as follows.

First, in SDG&E's TO3 Cycle 5 Compliance Order in ER11-4318-000, the Commission ordered SDG&E to remove capitalized wildfire costs (wildfire insurance premiums and wildfire damages to third parties) from transmission plant in service and to give these costs Account 925 treatment. Based upon the Cycle 5 Compliance Order, SDG&E had adjusted all applicable recorded costs of the TO4 Cycle 1 Base Period to remove capitalized wildfire costs and to give these costs Account 925 expense treatment. This is also discussed further in my testimony.

Second, in TO4, SDG&E is proposing to directly assign Electric Division Intangible plant to transmission and distribution in addition to allocating these costs using a labor ratio. Michelle Somerville in her testimony discusses and supports the direct assignment of intangible plant. I simply took the results of her direct assignments as discussed in her testimony and assigned it to transmission to develop Statement BK-1

Third, with regards to wildfire damages paid to third parties that are recorded in Account 925, I have removed those wildfire damages that were applicable to TO3 Cycle 5 and Cycle 6 because they are already being collected in those cycles, subject to refund. Later in my testimony, I will explain in more detail the amounts of these costs that I have removed from the Base Period Account 925.

Q9. Please explain the cost statements and related costs that are used to develop SDG&E's BTRR.

A9. To the extent that all costs from statements flow into Statement BK-1, I have included in my testimony Statement BK-1 as Exhibit No. SDG-4-1.

IV. DERIVATION OF TRANSMISSION PLANT AND OTHER PLANT ITEMS ALLOCATED TO TRANSMISSION

A. Derivation of Transmission Plant Balance

Q10. Please explain what costs are contained in Statement AD.

A10. Statement AD shown in Volume 4 indicates transmission plant and other electric plant amounts that are needed to determine Base Period transmission plant as well as to determine allocation factors that use plant balances to allocate other costs to transmission services. These other costs allocated to transmission service include property taxes and material and supplies. I will discuss these allocation factors shortly.

Q11. In SDG&E's TO3 Cycle 6 Supplemental filing in Docket ER12-2454-000 SDG&E removed capitalized wildfire insurance premiums and wildfire damages paid to third parties from transmission plant in service to conform to a FERC order related to this issue. Has SDG&E in its TO4 Cycle 1 transmission plant balances removed these capitalized costs from plant in service?

A11. Yes. Transmission rate base work papers in Volume 5 for Cost Statement AD, AE and AJ, shows how these costs were removed from the monthly transmission plant balances as well as other functional balances.

Q12. To reflect the removal of capitalized wildfire insurance premiums and wildfire damages paid to third parties have you made a corresponding adjustment to increase the Base Period wildfire insurance premiums and wildfire damages paid to third parties that are expensed and recorded to Account 925?

A12. Yes. I explain this more in Section 10 of my testimony.

B. Per Book Transmission Adjusted for Ratemaking for FERC Seven Factor Definition of Transmission (Transmission Ratemaking Balances)

Q13. Please explain in Volume 4 Statement AD, page AD-6 why SDG&E shows in column 1, per book monthly balances and in column 2 you show a transmission ratemaking balance.

A13. The two columns or the difference between the two columns results from the Seven-Element Adjustment Factor term as it appears in Appendix VIII. This term basically requires SDG&E to adjust its recorded plant balances by transferring a very small amount of transmission plant to its generation and distribution functions as well as by transferring a very small amount of distribution to its transmission plant. This requirement results from the industry restructuring that began in April 1998 pursuant to the Commission guidelines in FERC Order No. 888 related to the definition of transmission facilities.

Q14. Please elaborate.

A14. In 1998, SDG&E defined the transmission facilities that it would turn over to the ISO for operational purposes using the "seven-factor guidelines" set forth in FERC Order No. 888 to distinguish transmission from distribution. Under these guidelines, SDG&E identified a very small amount of per book transmission plant that should be transferred to the distribution function as well as a very small amount of plant that should be transferred from distribution to transmission. (The Commission approved SDG&E's delineation between transmission and distribution facilities in Docket No. EL96-48.) The adjustment of SDG&E's per book transmission plant is shown as the difference (column 2) in work paper Statement AD WP Page AD-6 line 17, column 2. As time goes by, I anticipate that this adjustment would change very slightly based upon the application of the guidelines for the “seven-factor element”.

To incorporate the ratemaking plant balances in past SDG&E formula cycle filings under TO3, SDG&E has included footnotes in its FERC Form 1 on page 450.1 that show the ratemaking plant balances for transmission, generation and distribution plant. These amounts are picked up in the formula and in any year, one can determine the differences in per book plant and ratemaking plant by simply taking the differences in both amounts. Both amounts are shown in FERC Form 1. Similarly, the ratemaking balances for accumulated depreciation reserve, page 450.1, and ratemaking depreciation expense, page 450.1, are shown in FERC Form 1. Under TO4, SDG&E will continue to include the above noted footnotes in its FERC Form 1.

C. Derivation of Other Statement AD Plant Balances to Develop SDG&E’s Transmission Plant Allocation Factor

Q15. Please explain the other plant amounts that are shown in Statement AD.

A15. In Statement AD we show other annual plant balances such as Steam Production, Nuclear Production, Other Production, Distribution, Transmission, General and Common plant balances. These balances are used in part to develop the Transmission Plant Allocation Factor as shown at the bottom of this Statement as well as the Transmission Related Property Tax Allocation Factor that I will address below regarding Statement AK.

Consistent with SDG&E’s TO3 methodology, the average costs of the various electric functional costs are averaged as shown in Exhibit No. SDG-4-2. The 13 month average methodology SDG&E has used in the past is shown in Volume 5 Statement AD pages AD-2; AD-3; AD-4; and AD-6. For transmission plant, the weighted average plant balance is calculated using a 13-month average (the sum of the monthly balances from month prior to the first month of the 12 month period through the last month of the 12 month period, less one-half of the first and last month). For future TO4 Cycles, the average plant balances will be based upon FERC Form 1 calendar recorded amounts.

Q16. Note should be made on Statement AD, SDG&E has put a placeholder for Incentive plant balances. Will SDG&E continue to show this placeholder in Statement AD?

A16. Yes. As Mr. Raulin Farinas explains in his testimony, in the future, Statement BK will show both Non-Incentive plant balances in its FERC Form 1 for the required rate base items of the formula. In addition, SDG&E will show in FERC Form 1 for each incentive project, applicable plant costs and in-service date. In this way, third parties will be able to keep track the incentives for which SDG&E is seeking rate recovery in its formula of approved incentives. Additionally, Mr. Farinas in his testimony shows some illustrative examples as to how these incentives will be calculated.

Q17. Please explain how you used the labor ratio (Transmission Wages and Salaries Allocation Factor) as shown in Exhibit No. SDG-4-3, line 27 of Statement AD.

A17. The total electric general and common plant shown on lines 21 and 23 is multiplied by the Transmission Wages and Salaries Allocation Factor (labor ratio) to derive the portion of general and common plant that supports transmission service. The result of this calculation is shown on lines 33 and 35. The derivation of this labor ratio is shown in Statement AI and will be explained later in my testimony. This allocation was used in TO3 and is commonly accepted by the FERC to allocate these types of costs.

D. Allocation of Common Plant to SDG&E's Electric Division and Subsequently to Transmission Service

Q18. Please explain how SDG&E's total common plant was allocated to the Electric Division.

A18. Total SDG&E's total Common Plant was allocated to the Electric division using a common plant labor allocator, consistent with the methodology in SDG&E's general rate case which is pending before the CPUC. In TO3, SDG&E used a Four Factor Allocator that the CPUC had previously approved. These Common Plant facilities are recorded in FERC Accounts 303 through 398.

Q19. Do you have a work paper that shows the amounts in Accounts 303 through 398?

A19. Yes, in Statement AD Volume 5, pages AD-8A and AD-8B, I have included the work papers that reflect for each account the ending balances for May 2011 and May 2012. Accumulated depreciation and depreciation expenses work papers associated with total Common Plant allocated between the Electric and Gas Division are reflected in Volume 5 under Statements AE and AJ respectively. The Electric Division allocation is equal to 72.32% as reflected in the Cost Statement AD work papers for common plant in Volume 5.

Q21. Once Common Plant is allocated to SDG&E's Electric Division, how is it allocated to transmission service?

A21. It is allocated using the Transmission Wages and Salaries Allocation Factor (labor ratio) as was done in TO3. Statement AI in Volume 5 shows the derivation of the Transmission Wages and Salaries Allocation Factor.

E. Allocation of Electric General Plant to Transmission Service

Q22. How is electric General Plant allocated to transmission service?

A22. The electric general plant facilities in the Electric Division are facilities that only support electric service and in no way support gas services. The electric general plant facilities are allocated to transmission service using the Transmission Wages and Salaries Allocation Factor, which is commonly referred to as the transmission labor ratio. Statement AD in Volume 5, page AD-7 shows this allocation. This labor allocation method for general plant to transmission reflects in the most part that electric employees use these facilities and as such an employee direct labor ratio is reasonable for this allocation. This allocation method is currently used by SDG&E in its TO3 formula.

Q23. Typically, what types of facilities are recorded in General Plant?

A23. General Plant consists of Accounts 389 through 399. Some examples of the facilities recorded in General Plant include:

- Account 390 (Structures and Improvements) includes those operating and maintenance sites and leasehold improvements that are used by employees to support electric only functions.
- Account 394 (Tools Shop and Garage equipment) includes various equipment that are used by employees to service electric only customers.
- Account 397 (Communication Equipment) includes communication equipment used by employees that supports electric substation functions, as well as electric only operating and maintenance locations.

Statement AD in Volume 5 page AD-7 reflects the average balance for these accounts using an end of May 2011 and end of May 2012 balance.

Q24. Why is it appropriate to allocate general plant using a Transmission Wages and Salaries Allocation Factor or labor allocator as derived in Statement AI?

A24. In general because electric employees use these facilities to support distribution and transmission services, an employee direct labor allocator is a reasonable allocation for these costs. This allocation method was also used in TO3 and its derivation is discussed below in a section of my testimony.

F. Derivation of Transmission Plant Allocation Factor

Q25. As shown at the bottom of Page 1 of Exhibit No. SDG-4-3 for Statement AD you develop a Transmission Plant Allocation Factor. Please explain how you developed this factor and how it is applied.

A25. As shown in Page 1, Exhibit No. SDG-4-3 for Statement AD, the Transmission Plant Allocation Factor, which is also used in TO3, is the ratio of transmission plant on line 37 and the sum of total production, distribution, transmission, common plant allocated to electric and electric general plant shown on line 25. This allocator is used to allocate total electric material and supplies and prepayments in working capital as shown in Statement AL. This factor was also used in TO3 and why this factor is used to allocate these costs is explained below in Statement AL.

V. DERIVATION OF TRANSMISSION ACCUMULATED DEPRECIATION RESERVE

Q26. Explain how you derived accumulated depreciation applicable to transmission rate base.

A26. Volume 5, Statement AE1, page AE-1 shows this derivation. Similar to Statement AD for transmission plant, the weighted average plant balance is calculated using a 13-month average (the sum of the monthly balances from month prior to the first month of the 12 month period through the last month of the 12 month period, less one-half of the first and last month). SDG&E used in the past TO3 filing. As with transmission plant, I adjusted these numbers by a “seven-factor guideline adjustment factor” to reflect the transfer of plant from transmission to distribution and from distribution to transmission as previously explained for Statement AD plant balances.

Q27. Explain how you derived accumulated depreciation applicable to general and common plant.

A27. For this filing, I used the average of the sum of beginning of period (BOP) and end of period (EOP) accumulated depreciation reserve balances for general and common plant as shown in Volume 5, Statement AE, page AE1, Lines 9 and 11 for the initial Base

Period. For future rate changes and informational filings, SDG&E will derive this figure by using the actual beginning of year (BOY) and end of year (EOY) reserve as shown on page 219 (general plant) and page 356 (common plant) in FERC Form 1. Lines 15 and 17 show the amounts of general and common plant allocated to transmission using the Transmission Wages and Salaries Allocation Factor. The above approach was used by SDG&E in TO3.

VI. DERIVATION OF ACCUMULATED DEFERRED INCOME TAXES

Q28. Please explain any other reductions you make to rate base.

A28. The amount of accumulated deferred income taxes shown on page 3 of Exhibit No.SDG-4-3 was brought forward from Statement AF workpapers as shown in Volume 5, page AF1. In the future, amounts for both Non-Incentive and Incentive accumulated deferred income taxes will come from the appropriate pages in FERC Form 1 that are referenced in the formula cost statements.

VII. DERIVATION OF WORKING CAPITAL

Q29. How were the material and supplies and prepayment components of working capital allocated to transmission?

A29. Page 9 of Exhibit No.SDG-4-3 shows this derivation. I used the amounts shown in Statement AL shown in Volume 5, Page AL1. On this page, I show how I allocated total electric material and supplies and prepayments to transmission using the Transmission Plant Allocation Factor shown on line 3. For future formula filings, this allocation factor will be used, which was the same factor used in TO3.

Q30. Why is it appropriate to allocate these costs using gross plant?

A30. The level of material and supplies and prepayments are closely correlated to how gross plant changes and as such, this correlation makes the Transmission Plant Allocation Factor a reasonable allocator to use.

Q31. How did you derive working cash, which is part of working capital?

A31. On the same page 9 of Exhibit No. SDG-4-3, I multiplied the total amount of transmission O&M and A&G expenses allocated to transmission by one eighth. This calculation reflects the one eighth O&M rule that the Commission has traditionally used to derive working cash.

VIII. DERIVATION OF TRANSMISSION RATE BASE

Q32. Please explain how you developed transmission rate base?

A32. As shown in Exhibit No. SDG-4-1, Statement BK-1, page 2, the Transmission Rate Base is derived by taking the sum of net plant, plus plant held for future use and transmission abandoned project cost, less transmission accumulated deferred income taxes, plus various components of working capital. Cost Statements that support the above rate base components are included in the applicable cost statements or work papers in Volumes 4 and 5.

IX. DERIVATION OF TRANSMISSION O&M EXPENSES

Q33. Explain how you derived transmission O&M expenses.

A33. Exhibit No. SDG-4-3, page 5, shows this derivation. Line 1 shows total transmission O&M expenses as they appear in Statement AH for the initial Base Period. This amount comes from Statement AH, Volume 5, page AH2. For future rate changes and informational filings, we will obtain this amount from page 321, line 112 of column b of SDG&E's FERC Form 1, adjusted by certain exclusions. Exhibit No. SDG-4-4 shows the expenses that were excluded from per book transmission O&M expenses. This page shows the exclusion of expenses from FERC Account Nos. 561, 565, and 566.

Q34. Please explain these excluded O&M expenses?

A34. As shown in Exhibit No. SDG-4-4, the excluded expenses are footnoted starting on lines 37 to 45. FERC Account 561.4 for Scheduling, System Control and Dispatch Services of $7.9 million and FERC Account 561.8 for Reliability, Planning and Standards Development Services of $1.7 million were excluded as these costs represents CAISO charges recovered in the Energy Resource Recovery Account (ERRA), an SDG&E CPUC jurisdictional distribution rate.

Another expense that was excluded is shown in FERC Account 565, Transmission of Electricity by Others such as the Portland General Electric, NV Energy, and Fale Safe Inc. This expense is incurred to wheel SDG&E energy that is procured from these companies for SDG&E's bundled customers and is also recovered in the ERRA.

FERC Account 566 for Miscellaneous Transmission Expenses exclusions consisted of $3.7 million for ISO Grid Management Costs (GMC) that is also recovered in ERRA. The ($2.2) million of Reliability Service Must Run cost on line 42 represents debit charge due to settlement payment adjustments to billing errors that charged SDG&E more than what should have been by NRG, owner of Cabrillo 1 (the Encina Plant in Carlsbad) and Duke for South Bay. These costs are recovered in SDG&E's annual FERC Reliability Services filing.

Another exclusion from FERC Account 566 was the Transmission Revenue Balancing Account Adjustment (TRBAA) and Transmission Access Charge Balancing Account Adjustment (TACBAA) of $0.2 million shown on line 43. This amount is considered a miscellaneous transmission expenses by SDG&E and is booked in this account. However, it is excluded in the instant filing as this expense represents TRBAA and TACBAA charged to SDG&E's bundled customers and these charges are CPUC jurisdictional distribution rates.

The other miscellaneous transmission expense exclusion of $1 million is to normalize the transmission O&M expenses for the wildfire damage expenses that were recorded to A&G FERC Account 925, consistent with the Commission's directives in SDG&E's Cycle 5 proceeding.[1]

Q35. In future annual formula filings, will SDG&E provide this work paper?

A35. Yes. In SDG&E's past TO3 annual formula filings, SDG&E provided this work paper. The first column of the work paper ties to SDG&E's total electric transmission O&M expenses shown on page 321 of its FERC Form 1. The second column shows the expenses that are excluded in each primary account. SDG&E will continue to include this work paper in future TO4 annual formula filings work papers.

X. DERIVATION OF A&G EXPENSES ALLOCATED TO TRANSMISSION SERVICE

Q36. Explain how you derived A&G expenses allocated to transmission.

A36. Page 5 of Exhibit No SDG-4-3, Statement AH, shows this derivation. On line 57, I show total A&G expenses as they appear in Statement AH for the Base Period. Because total per book transmission A&G expenses contain expenses exclusively related to CPUC related programs for retail service and not to the provision of transmission service, these expenses are appropriately excluded from transmission revenue requirements. Exhibit

[1] *See* Delegated Order, 141 FERC ¶61,265 (2012).

No. SDG-4-6, lines 24 to 32 shows the detail as to what A&G expenses were excluded by primary FERC accounts. This exhibit is shown as a work paper in Volume 5, Statement AH, page AH3 and indicates the nature of each excluded expense by primary account.

Q37. Please describe some of the major expense exclusions shown in Exhibit No. SDG-4-5.

A37. An adjustment of $45 and $159 million on lines 25 and 26, column G, were made to the costs recorded in FERC Account 925 to remove wildfire damages claims to third parties that were applicable to the TO3 Cycle 5 and 6 filings respectively and as such were removed. An adjustment of $4.6 million was made to the costs recorded in FERC Account No. 928, line 27 to remove CPUC reimbursement fees that are not applicable to transmission service. An adjustment of $10.5 million was made to the costs recorded in FERC Account Nos. 926 and 930, line 30 to remove CPUC energy efficiency program costs, which are collected in CPUC jurisdictional distribution rates. It is appropriate for these expenses to be removed because they are not related to the provision of transmission service, and are recovered as part of distribution rates authorized by the CPUC.

Q38. In future TO4 annual filings, will SDG&E provide Exhibit No. SDG-4-5?

A38. Yes. Similar to SDG&E's TO3 Formula annual filings, SDG&E will provide this exhibit as a work paper. The adjusted per books column of the work paper will tie to SDG&E's total electric A&G expenses shown on page 323 of its FERC Form 1, while the excluded column shows the expenses that are excluded in each primary account. SDG&E will continue this practice.

Q39. Please finish explaining the process you used to allocate A&G expenses to transmission service.

A39. On page 5 of Statement AH (Exhibit No. SDG-4-3), I separately show the removal of these A&G expenses that were excluded from transmission service to arrive at the adjusted A&G expenses on line 28. I also exclude the property insurance expense since this will use a different allocation factor as shown on line 29. I then take the net amount on line 30 and multiply it by the Transmission Wages and Salaries Allocation Factor, as shown on line 31 to arrive at A&G expenses allocable to transmission service.

Q40. How did you allocate property insurance to transmission service?

A40. I allocated property insurance using a Transmission Plant Property Insurance Allocation Factor that reflects the exclusion of nuclear generation plant. As shown on line 29 of Statement AH, Exhibit No. SDG-4-3, I have removed property insurance from the total A&G expenses. I then took the property insurance costs and allocated these costs to transmission plant on the basis of the Transmission Plant Property Insurance Allocation Factor. This allocation factor is equal to the ratio of gross transmission plant and transmission related general common plant to total electric gross plant, excluding nuclear plant. I show these calculations in the lower half of Statement AH. I then show the total A&G expenses allocated to transmission service, which is the sum of A&G and property insurance expenses as shown on the last line of Statement AH. I then carried forward this amount to page 1 of Statement BK-1. For future annual formula filings, this same methodology that was used in SDG&E's TO3 formula will be used to derive allocated A&G expenses.

XI. DERIVATION OF TRANSMISSION DEPRECIATION EXPENSE

Q41. Explain how you derived depreciation expense applicable to transmission.

A41. Page 7 of Statement AJ (Exhibit No. SDG-4-3), shows this derivation. For this filing, I used transmission depreciation expense as shown in Statement AJ from Volume 5. These depreciation expenses are recorded and reflected in the SDG&E Base Period and reflect what was approved by the Commission in TO3. As discussed in the testimony of Ed Lucero and Bob Wieczorek, SDG&E in the instant filing is proposing new transmission depreciation expenses which SDG&E intends to begin recording September 2013, which is the first month these new expenses will be recorded subject to FERC approving these new rates. For future BTRR rate filings and informational filings under TO4, we would derive depreciation expenses by using the actual expense shown on page 336, line 7, column F of SDG&E's FERC Form 1 adjusted by the FERC Seven Element Adjustment Factor. As in past TO3 formula filings, we will include a page in FERC Form 1 that shows the transmission depreciation expense adjusted by the Seven Element Adjustment Factor.

Q42. Explain how you derived depreciation expense applicable to general and common plant.

A42. For this filing, I used the depreciation expense for general and common plant as shown in Statement AJ, page AJ1 in Volume 5. For future informational cyclical filings, we would derive this figure by using the actual expense shown on page 336 (general plant) and page 336 (common plant) of SDG&E's FERC Form 1. Exhibit No. SDG-4-3, page 7, lines 15 and 17, shows the amounts of general and common plant allocated to transmission using the Transmission Wages and Salaries Allocation Factor. Line 19 shows the sum of transmission depreciation and general and common plant depreciation allocated to transmission.

Q43. Please explain the Valley Rainbow Project Cost Amortization Expense equal to $1.893 million shown on line 23.

A43. On page 5 of SDG&E's TO3 Offer of Settlement (see SDG&E Exhibit SDG-2-1 of Mr. Lucero's testimony), FERC authorized SDG&E to recover, commencing October 1, 2003, Valley Rainbow abandoned costs equal to $18,926,940 over a ten-year amortization period expiring on September 2013. For the period covered by the TO3 Formula, this annual amortization amount will equal $1,892,694 per year.

To the extent the amortization of this cost will end in September 2013, one twelfth of this amount will be just once in TO4, which will be in the first TO4 TU Adjustment period that included this month. That is, this amount will equal $157,724 ($1,892,694/12) and is reflected in Appendix VIII as discussed by Leonor Sanchez.

XII. TRANSMISSION ABANDONED PROJECT COST AMORTIZATION EXPENSE

Q44. In Exhibit No. SDG-4-1, page 1 line 14, you show an item called Transmission Abandoned Project Cost Amortization Expense. Please explain this term.

A44. Although this item is blank in this filing, this serves as a place holder to permit SDG&E to recover incentives that the Commission may approve for future transmission projects. Leonor Sanchez in her testimony elaborates a bit more about this subject in the discussion of Appendix VIII.

XIII. TRANSMISSION RELATED PROPERTY TAXES AND OTHER TAXES OTHER THAN INCOME TAXES

Q45. Describe how you derived taxes other than income taxes allocated to transmission service.

A45. Page 8, Statement AK, (Exhibit No. SDG-4-3), I show this derivation. On line 1, I show total property taxes, which came from Statement AK for the initial Base Period. For future rate changes and informational filings, we will use the total property taxes as recorded on page 263, line 2, column I of the FERC Form 1. As shown in Statement AK, I allocate property taxes using a Property Tax Allocation Factor equal to total gross transmission plant divided by total gross electric plant. The derivation of this Property Tax Allocation Factor is shown beginning on line 8. The San Onofre Nuclear Generating Station (SONGS) property tax equal to $4.1 million was first excluded from this amount as SDG&E could directly determine this amount. The use of the Property Tax Allocation Factor was used in TO3 as property taxes are directly correlated with gross plant.

The Payroll taxes shown on Page 8 come from Statement AK, Volume 5, page AK1. However, for future rate changes and informational filings, SDG&E will develop payroll taxes from page 263 of the FERC Form 1. SDG&E will then allocate total payroll taxes to transmission using the Transmission Wages and Salaries Allocation Factor, as shown on line 32. This method to allocate payroll taxes was used in TO3 as the labor allocator is directly correlated with payroll taxes that are paid.

XIV. DERIVATION OF OTHER INCOME TAX ITEMS ALLOCATED TO TRANSMISSION SERVICE

Q46. What income tax adjustments did you make to the cost of service?

A46. The income tax adjustments made to the cost of service came from Statements AQ and AR (Exhibit No. SDG-4-3, pages 10 and 11) for the initial Base Period. SDG&E made two income tax adjustments. The first adjustment made to its cost of service is the inclusion of a South Georgia income tax adjustment to its retail cost of service, i.e., $BTRR_{EU}$. This income tax adjustment is derived in the same manner as in TO3 and is addressed more in Appendix VIII, which is discussed in the testimony of Leonor Sanchez. The second adjustment is an Amortization of Investment Tax Credit (ITC) expense that reduces cost of service. This adjustment comports with SDG&E's past practice of booking ITC related to prior plant additions. Essentially, SDG&E must flow back to customers the ITC benefits it received in prior years. Similar to the South Georgia adjustment discussed above, the Amortization of ITC Tax Credit is derived in the same manner as in TO3 and is addressed more in Appendix VIII, which is discussed by Leonor Sanchez.

XV. DERIVATION OF REVENUE CREDITS

Q47. Explain how you derived the revenue credits applicable to the TO4 Formula.

A47. Revenue credits come from page 12 of Statement AU (Exhibit No. SDG-4-3 for the Cycle 1 Base Period). The amounts on this page come from Volume 5, Pages AU1 to AU2. The revenue credits related to transmission service come from the following sources:

- Account No. 454, Rent from Electric Property.
- Account No. 456, Other Electric Revenue. Wheeling revenues normally booked in this account are not reflected in the formula, as these amounts are credited back to End Use Customers through SDG&E's TRBAA credit.

Q48. What makes up the largest share of revenue credits?

A48. The largest share of revenue credits comes from Shared Asset Revenues booked in Account No. 456. These revenues are related to SDG&E's general and common plant facilities that are used to provide shared services to SDG&E's unregulated affiliates. In providing shared services to its affiliates, SDG&E charges these affiliates prices equal to the embedded cost of service related to these shared facilities. In this way, ratepayers do not subsidize the cost of service related to these shared assets.

Q49. For future rate changes and annual informational filings, how will revenue credits be derived and shown?

A49. For future rate changes and informational filings, revenue credits will be derived from SDG&E's FERC Form 1 and work papers will be filed as shown in Volume 5 Statement AU that shows detail monthly balances of the revenue credits charged to FERC Accounts 454 and 456.

Q50. Why did you not include as a revenue credit revenues from wholesale transactions utilizing SDG&E's portion of the ISO Controlled Grid?

A50. Revenues from wholesale transactions, such as Wheeling-Out and Wheeling-Through Revenues, Usage Charge Revenues, and Firm Transmission Right proceeds resulting from the ISO annual FTR auction were excluded in calculating SDG&E's total Transmission Revenue Requirement. These revenues are credited to End Use customers through SDG&E's separate Transmission Revenue Balancing Account Adjustment filing, which SDG&E normally files in December of each year as described in the SDG&E's TO Tariff.

XVI. DERIVATION OF TRANSMISSION WAGES AND SALARIES ALLOCATION FACTOR

Q51. Explain how you derived the Wages and Salaries Allocation Factor used in the formula as shown on Statement AI.

A51. The derivation of this allocation factor, commonly referred to as the transmission labor ratio, is shown on Statement AI and follows the approach commonly adopted by the FERC to allocate A&G expenses as well as General and Common Plant. That is, I have allocated the total transmission direct labor shown in line 3 by the ratio of the total electric direct labor that excluded the direct labor related to A&G wages and salaries as shown in line 11 of Exhibit No. SDG-4-3. The result is shown on line 13 at 14.44%. Consistent with its current TO3 annual formula filings, in future TO4 annual formula filings, SDG&E will continue using labor ratios of its Wages and Salaries Allocation Factor to allocate A&G expenses and general and common plant. For Cycle 1, SDG&E is using the labor ratio for 12 months to date May 31, 2012. For future filings, SDG&E will use the direct labor dollars as shown on page 354 in SDG&E's FERC Form 1 as of December of the applicable year.

XVII. DERIVATION OF COST OF CAPITAL AND INCOME TAXES RELATED WITH COST OF CAPITAL

Q52. Explain how you derived the cost of capital used for the formula.

A52. Page 13, Statement AV, shows this calculation. SDG&E is proposing to use its current formula method to calculate its cost of capital shown in Statement AV. For this Cycle 1 filing, I am using recorded information as of May 31, 2012, the end of Base Period, to determine the capital structure.

Q53. In developing the components of SDG&E's capital structure, do you define the specific FERC accounts that make up each capital structure component?

A53. Yes. Page 13, lines 1 through 30, show the accounts that make up the debt, preferred stock, and equity components of the capital structure. The accounts and amounts shown on these lines show up in SDG&E's annual FERC Form 1 for December 31 of the applicable year. For this filing and as shown on Statement AV page 13, I am using the amounts for these accounts as of May 31, 2012. I show how the above amounts are used to develop SDG&E's weighted cost of capital for the rate base on lines 32 through 43 and for the Incentive Rate Base on lines 45 to 56.

For the rate base I am using a cost of equity equal to 11.30%, which is made up of a base ROE equal to 10.8% and a 50 basis point adder for participating in the ISO as a PTO. Support for the 10.8% base ROE is noted in Dr Morin's testimony. For the Incentive Rate Base, Raulin Farinas in his testimony is using a slightly higher ROE for illustrative purposes to develop incentive revenue examples. However, whatever ROE incentive adder is used will be subject to approval by the FERC through a separate Section 205 filing as explained by Mr. Lucero in his testimony.

Q54. How did you derive the cost of capital to calculate the return and income taxes for the rate base and Incentive rate base in the cost of service, Statement BK-1 page 1?

A54. In order to calculate return and income taxes in Statement BK applicable to the rate base, I use a Cost of Capital Rate methodology that is currently used in the TO3 formula filings. As reflected in Appendix VIII as discussed by Leonor Sanchez, the cost of capital as reflected in Statement AV is at the end of the Base Period. In the instant filing the cost of capital is as of May 31, 2012. The cost of capital rate methodology that I use for Incentive Rate Base was modified slightly as I explained further in my testimony. This calculation is described further in Section II of Appendix VIII.

Q55. In Cost Statement AV in Volume 4, page 14, lines 8 and 21 you show a component "C" entitled "Equity AFUC Component of Transmission Depreciation Expenses" that is used to develop the Federal and State income tax component related with cost of capital. In TO4 do you intend to populate this item?

A55. Yes. In TO3 SDG&E did not populate this item but in TO4 SDG&E will populate this amount beginning with TO4 Cycle 2. Specifically we will populate it for the Cycle 2 Base Period and the first TU Period.

Q56. Please explain the rationale for including the Equity Allowance for Funds Used During Construction (AFUDC) Component of Transmission Depreciation Expense to Develop Income Taxes.

A56. The revenue requirement for income taxes includes a gross-up for the impact that Equity AFUDC has on the profits taxed by federal and state taxing authorities. Equity AFUDC is a ratemaking concept that provides equity investors a fair after-tax return during construction of plant. Equity AFUDC ultimately gets into rate base and impacts earnings by increasing the return on rate base (ROR) in the revenue requirement.

Equity AFUDC and the Equity ROR follow the same revenue requirement concept with two distinct differences. First, while Equity AFUDC and Equity ROR both generate after-tax profit, there is a timing difference in the recognition of that profit in the financial statements. The after-tax profit generated by Equity AFUDC is recognized in the financial statements during the construction period as costs accumulate in Construction Work-in-Progress (CWIP). In contrast, the after-tax profit generated by Equity ROR is recognized in the financial statements after construction costs have been reclassified from CWIP to Plant-in-Service and the property is put into rate base.

Another distinction between Equity AFUDC and Equity ROR relates to when cash revenue is generated. During the CWIP period, the company recognizes book profits as Equity AFUDC is loaded to CWIP, but no cash revenue is received. Then, during the period when the property is in rate base, cash is generated through the revenue requirement for book depreciation (which is computed by applying a depreciation rate against a book basis that includes the Equity AFUDC loaded during construction). Thus for Equity ROR, the cash revenue is received the same year that the Equity ROR is reflected in the financial statements.

At the same time cash revenue is recovered through the revenue requirement for book depreciation, there is no offsetting Equity AFUDC in the tax basis used to compute tax depreciation. Taxable income is computed by adding book depreciation back to pretax book income and deducting tax depreciation in its place, therefore, the Equity AFUDC component of book depreciation ends up being taxable profit subject to federal and state income taxes. The tax gross-up is needed to recover the revenue requirement for this tax effect.

XVIII. DERIVATION OF END USE CUSTOMER BTRR FOR THE INITIAL BASE PERIOD INCLUDING FORECAST PERIOD AND TRUE-UP ADJUSTMENT REVENUE COMPONENTS

A. Derivation of End Use Customer $BTRR_{EU}$ Formula Revenues for the Initial Base Period (Prior Year Revenue Requirement (PYRR)

Q57. Please explain how you calculated the recorded initial Base Period cost of service ended May 2012 as shown in Statement BK-1 Volume 4.

A57. Exhibit No. SDG-4-1 shows Statement BK-1 or the derivation of the cost of service, which derives retail transmission revenue requirements. Statement BK-1 consists of six pages:

- Page 1 shows the summary cost of service for the initial Base Period PYRR for both transmission rate base revenue and incentive transmission revenue.
- Page 2 shows the development of rate base for the initial Base Period PYRR for both transmission rate base and incentive transmission rate base.
- Page 3 shows the development of net plant for both transmission and Incentive transmission projects.
- Page 4 shows the development of the Annual Fixed Charge Rate (AFCR) used to develop revenues applicable to forecast plant additions and a corresponding AFCR to develop revenues related to Plant Held for Future Use.
- Page 5 shows the development of AFCRs applicable to Incentive projects for an ROE adder, accelerated depreciation incentive, and CWIP in ratebase.
- Page 6 summarizes the total retail $BTRR_{EU}$ formula revenue requirements for the initial Base Period PYRR and the forecast revenue requirements (FCRR).

B. Development of the Initial Base Period Cost of Service Statement BK-1

Q58. Please describe the development of the initial Base Period Cost of Service Statement BK-1- Page 1.

A58. Page 1 develops the total cost of service for the initial Base Period PYRR. Section A develops the transmission revenues, Lines 1 through 35, and brings forward cost data from either the succeeding pages of Statement BK-1 or from the cost statements that I previously described in my testimony as are shown in my Exhibit No. SDG-4-3. Column 3 references the source of this data. On line 22, I show how I bring forward the grossed up return from Statement AV. When this grossed up return is multiplied times rate base as shown on line 26, it recovers the total cost of capital, including the return on equity, as well as the federal and state income taxes.

On line 28, I show the inclusion of the South Georgia income tax adjustment to retail transmission revenue requirements from Statement AQ, line 29 is the Transmission Related Amortization of ITC from Statement AR and on line 31, I show the inclusion of the Transmission Related Revenue Credits that come from Statement AU. Line 35 shows the total PYRR for End Use Customers for the Initial Base Period. In Section B, I develop the revenues related to Incentive projects, which brings forward incentive cost data from either the succeeding pages of Statement BK-1 or from the cost statements that I previously described in my testimony as are shown in my Exhibit No. SDG-4-3.

Q59. Please describe the development of Transmission Rate Base – Page 2.

Q59. Section A on page 2 shows the development of Transmission rate base for the initial Base Period. Column 3 cross-references all cost data on this page to the cost statements in Exhibit No. SDG-4-3. Section B on page 2 shows the development of Incentive rate base for the initial Base Period. Column 3 cross-references all cost data on this page to the cost statements in Exhibit No. SDG-4-3.

Q60. Please describe the development of Net Plant – Page 3.

Q60. Section A on page 3 shows the development of transmission plant for the initial Base Period. Column 3 cross-references all cost data on this page to the cost statements as shown in Exhibit No. SDG-4-3. Section B on page 3 shows the development of Incentive net plant for the initial Base Period. Column 3 cross-references all cost data on this page to the cost statements as shown in Exhibit No. SDG-4-3.

Q61. Relative to the derivation of BTRR for Forecast Plant Additions (FCRR), please describe how you developed transmission revenue requirements for the Forecast of transmission, general and common plant additions, referred to as FCRR, which make up the second part of the BTRR formula.

A61. The second part of the BTRR formula recovers the costs related to forecast plant additions from the end of the Base Period to the end of the Rate Effective Period. This filing has a 27-month forecast period of June 2012 through August 2014.

Q62. What is the purpose of recovering the revenue requirements related to the Forecast Plant additions?

A62. As Mr. Jenkins discusses, SDG&E anticipates significant capital additions and replacements to existing infrastructure over the Forecast Period. In dollar terms, those additions will substantially exceed depreciation of existing plant. To avoid a chronic revenue shortfall for the foreseeable future, it will be necessary to track these costs on a current basis as capital additions go into service. The monthly forecast plant addition costs adjusted for retirements are shown in Volume 5, Section Q, Summary of Weighted HV-LV Forecast Plant Additions work papers, representing plant additions that will go in to service and be used and useful to customers during the Forecast Period, and will be billed to customers during the Rate Effective Period, September 2013 through August 2014.

As mentioned previously and discussed in more detail later in my testimony, as well as in Mr. Lucero's testimony, SDG&E's TO4 Formula includes a True-Up Adjustment component that will ensure SDG&E's transmission customers pay no more or no less than the actual costs SDG&E incurs to provide transmission service during the Rate Effective Period.

Q63. How did you calculate the revenue requirements related to the forecast plant additions shown in the Forecast Period?

A63. Page 4 of Statement BK-1, Part A shows this calculation. I first calculated an AFCR, line 14, using cost data from the Base Period. This procedure is the same procedure that SDG&E currently uses in its TO3 annual formula filings. I then multiplied this AFCR by the weighted plant additions that I refer to above to derive Forecast Period project revenues. The weighted project costs can be found in Volume 5. The project plant amounts shown in this work paper in turn come from various work papers in Volume 5, Sections R to Y which show for the Forecast Period, the name, cost and the month each project goes into service.

Q64. Please explain why and how you calculated the weighting applied to the forecast plant additions?

A64. The procedure I used for weighting the various monthly project costs is described in Mr. Lucero's testimony.

Q65. Where do you show the total $BTRR_{EU}$, including the PYRR and FCRR?

A65. On page 6, I show the total for these amounts to derive total $BTRR_{EU}$. I then use this amount to allocate revenue requirements among retail customer classes that receive transmission services under SDG&E's TO Tariff. This is explained further in my testimony.

Q66. Please explain how you accounted for franchise fees and uncollectible expenses on page 6.

A66. On page 6 line 34, I show the derivation of uncollectible expenses that SDG&E must recover that are related to transmission services. This expense pertains to the failure of some retail customers to pay their electric bill during the year, thus some retail revenues are uncollectible. I take the $BTRR_{EU}$ multiplied by the allowance for uncollectible approved by the CPUC, which is currently 0.141% based upon the most recent approved CPUC authorized decision for SDG&E.

Franchise fees are shown separately in two places. First, on page 6, line 33, I take the $BTRR_{EU}$, which excludes franchise fees, and multiply this amount by a base franchise fee percentage. The current CPUC-approved percentage is 1.0275%. Line 33 shows this base franchise amount, which the formula defines in Appendix VIII Transmission Related Municipal Franchise Tax Expenses. SDG&E pays this base franchise percentage factor and in turn, recovers this expense from all End Use Customers both within its service area, including those served within the City of San Diego. I then add this amount to $BTRR_{EU}$ and use this to design End Use Customer transmission rates.

Second, SDG&E charges a separate franchise fee surcharge that is applied to the $BTRR_{EU}$. This surcharge, which is approved by the CPUC, is paid by SDG&E to the City of San Diego and, in turn, SDG&E recovers this expense from all End Use Customers serviced within the City of San Diego. This separate amount is noted in Appendix VIII in the definition of Transmission Related Municipal Franchise Tax Expenses. This amount is shown separately on the monthly utility bill received by each customer who lives within the San Diego city limits and, therefore, is not included in the design of retail End Use customer transmission rates.

C. True-Up Adjustment

Q67. Please explain what you mean by the True-Up Adjustment provision.

A67. The True-Up Adjustment provision of the formula will be utilized in calculating the transmission revenue requirements applicable beginning in TO4 Cycle 2 Rate Effective Period commencing September 1, 2014. The purpose of the provision, as used in SDG&E's past TO3 formula filings is to ensure SDG&E collects no more and no less than its allowed cost of service at its authorized return on equity, equal to 11.30% or the ROE determined in the instant filing.

Q68. How is the True-Up Adjustment Calculated?

A68. Mr. Lucero in his testimony explains how this Adjustment is calculated.

XIX. COST STATEMENTS

Q69. Ms. Tanedo, what cost statements are you sponsoring in this proceeding?

A69. I'm sponsoring the following cost statements:

- Statement AD – Cost of Plant
- Statement AE – Accumulated Depreciation and Amortization
- Statement AF – Deferred Credits
- Statement AG – Specified Plant Account (Other than Plant in Service) and Deferred Debits
- Statement AH – Operation and Maintenance Expenses
- Statement AI – Wages and Salaries
- Statement AJ – Depreciation and Amortization Expense
- Statement AK – Taxes Other Than Income Taxes
- Statement AL – Working Capital
- Statement AQ – Federal Income Tax Deductions, Other Than Interest
- Statement AR – Federal Tax Adjustments
- Statement AU – Revenue Credits
- Statement AV – Cost of Capital and Fair Rate of Return

Q70. Does this conclude your testimony?

A70. Yes, it does.

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. Revenues:**			1
2	Transmission Operation & Maintenance Expense	$ 51,765	Statement AH; Page 5, Line 8	2
3				3
4	Transmission Related A&G Expenses	42,175	Statement AH; Page 5, Line 57	4
5				5
6	CPUC Intervenor Funding Expense	-	Statement AH; Page 5, Line 9	6
7				7
8	Total O&M Expenses	$ 93,940	Sum Lines 2 thru 6	8
9				9
10	Transmission, Intangible, General and Common Depr. & Amort. Expense	54,756	Statement AJ; Page 7, Line 19	10
11				11
12	Valley Rainbow Project Cost Amortization Expense	1,893	Statement AJ; Page 7, Line 23	12
13				13
14	Transmission Abandoned Project Cost Amortization Expense	-	Statement AJ; Page 7, Line 25	14
15				15
16	Transmission Related Property Taxes Expense	11,156	Statement AK; Page 8, Line 27	16
17				17
18	Transmission Related Payroll Taxes Expense	2,030	Statement AK; Page 8, Line 34	18
19				19
20	Sub-Total Expense	$ 163,775	Sum Lines 8 thru 18	20
21				21
22	Cost of Capital Rate $_{(COCR)}$	11.8690%	Statement AV; Page 14, Line 33	22
23				23
24	Transmission Rate Base	$ 1,219,088	Statement BK-1; Page 2, Line 26	24
25				25
26	Return and Associated Income Taxes	$ 144,694	Line 22 x Line 24	26
27				27
28	South Georgia Income Tax Adjustment	2,333	Statement AQ; Page 10, Line 1	28
29	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11, Line 1	29
30	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement AR; Page 11, Line 3	30
31	Transmission Related Revenue Credits	(2,652)	Statement AU; Page 12, Line 11	31
32	Transmission Related Regulatory Debits	-	Not Applicable in TO4-Cycle 1	32
33	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement AU; Page 12, Line 13	33
34				34
35	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$ 307,885	Line 20 + Sum Lines (26 thru 33)	35
36				36
37	**B. Incentive Revenues:**			37
38	Incentive Transmission Plant Depreciation Expense	$ -	Statement AJ; Page 7; Line 21	38
39	Sub-Total Expense	$ -	Sum Lines 38	39
40				40
41	Incentive Cost of Capital Rate $_{(ICOCR)}$	0.0000%	Statement AV; Page 15; Line 33	41
42	Incentive Transmission Rate Base	$ -	Statement BK-1; Page 2; Line 39	42
43				43
44	Incentive Return and Associated Income Taxes	$ -	Line 41 x Line 42	44
45				45
46	Incentive End of Prior Year Revenues (PYRR $_{EU-IR}$) Excluding FF&U	$ -	Sum Lines 39; 44	46
47				47
48	**C. Total (PYRR $_{EU}$) Excluding FF&U [1]**	$ 307,885	Sum Lines 35; 46	48

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for 12 months ending May 31, 2012.

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Rate Base			
1	Net Transmission Plant:			1
2	Transmission Plant	$ 1,256,940	Statement BK-1; Page 3; Line 16	2
3	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Statement BK-1; Page 3; Line 17	3
4	Transmission Related General Plant	16,585	Statement BK-1; Page 3; Line 18	4
5	Transmission Related Common Plant	32,956	Statement BK-1; Page 3; Line 19	5
6	Total Net Transmission Plant	$ 1,307,515	Sum Lines 2 thru 5	6
7				7
8	Rate Base Additions:			8
9	Transmission Plant Held for Future Use	$ 66,487	Statement AG; Page 4; Line 3	9
10	Transmission Abandoned Project Cost	-	Not Applicable in TO4-Cycle 1	10
11	Total Rate Base Additions	$ 66,487	Sum Lines 9 thru 10	11
12				12
13	Rate Base Reductions:			13
14	Transmission Related Accum. Def. Inc. Taxes	$ (184,167)	Statement AF; Page 3; Line 5	14
15	Transmission Related Abandoned Accum. Def. Inc. Taxes	-	Not Applicable in TO4-Cycle 1	15
16	Total Rate Base Reductions	$ (184,167)	Sum Lines 14 thru 15	16
17				17
18	Working Capital:			18
19	Transmission Related Material and Supplies	$ 11,278	Statement AL; Page 9; Line 5	19
20	Transmission Related Prepayments	6,232	Statement AL; Page 9; Line 9	20
21	Transmission Related Cash Working Capital	11,743	Statement AL; Page 9; Line 19	21
22	Total Working Capital	$ 29,253	Sum Lines 19 thru 21	22
23				23
24	Other Regulatory Assets/Liabilities	-	Not Applicable in TO4-Cycle 1	24
25				25
26	Total Transmission Rate Base	$ 1,219,088	Sum Lines 6; 11; 16; 22; 24	26
27				27
28	**B. Incentive Transmission Rate Base**			28
29	Net Incentive Transmission Plant	$ -	Statement BK-1; Page 3; Line 25	29
30				30
31	Rate Base Addition:			31
32	Transmission Construction Work In Progress for Incentive Projects	$ -	Not Applicable in TO4-Cycle 1	32
33	Total Rate Base Addition	$ -	Sum Line 32	33
34				34
35	Rate Base Reduction:			35
36	Incentive Transmission Plant Related Accum. Def. Income Taxes	$ -	Statement AF; Page 3; Line 7	36
37	Total Rate Base Reduction	$ -	Sum Line 36	37
38				38
39	Total Incentive Transmission Rate Base	$ -	Sum Lines 29; 33; 37	39

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Plant			
1	Gross Transmission Plant:			1
2	Transmission Plant	$ 1,785,708	Statement AD; Page 1, Line 31	2
3	Transmission Related Electric Miscellaneous Intangible Plant	5,982	Statement AD; Page 1, Line 29	3
4	Transmission Related General Plant	29,185	Statement AD; Page 1, Line 33	4
5	Transmission Related Common Plant	67,986	Statement AD; Page 1, Line 35	5
6	Total Gross Transmission Plant	$ 1,888,861	Sum Lines 2 thru 5	6
7				7
8	Accumulated Depreciation Reserve:			8
9	Transmission Plant Depreciation Reserve	$ 528,768	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Miscellaneous Intangible Amortization Reserve	4,948	Statement AE; Page 2, Line 7	10
11	Transmission Related General Plant Depr Reserve	12,600	Statement AE; Page 2, Line 15	11
12	Transmission Related Common Plant Depr Reserve	35,030	Statement AE; Page 2, Line 17	12
13	Total Transmission Related Accumulated Depreciation Reserve	$ 581,346	Sum Lines 9 thru 12	13
14				14
15	Net Transmission Plant:			15
16	Transmission Plant	$ 1,256,940	Line 2 Minus Line 9	16
17	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Line 3 Minus Line 10	17
18	Transmission Related General Plant	16,585	Line 4 Minus Line 11	18
19	Transmission Related Common Plant	32,956	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	$ 1,307,515	Sum Lines 16 thru 19	20
21				21
22	**B. Incentive Transmission Plant**			22
23	Incentive Transmission Plant	$ -	Statement AD; Page 1, Line 17	23
24	Incentive Transmission Related Accumulated Depreciation Reserve	-	Statement AE; Page 2, Line 3	24
25	Total Net Incentive Transmission Plant	$ -	Line 23 Minus Line 24	25

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC_{EU})
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate ($AFCR_{EU}$) Applicable to**			1
2	**Weighted Forecast Plant Additions:**			2
3	$PYRR_{EU}$ Excluding Franchise Fees and Uncollectible	$ 307,885	Statement BK-1; Page 1; Line 35	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement BK-1; Page 1; Line 33	9
10	Total (PYRR EU) Excluding FF&U - Adjusted	$ 303,924	Sum Lines 3 thru 9	10
11				11
12	Gross Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	12
13				13
14	Annual Fix Charge Rate ($AFCR_{EU}$)	16.0903%	Line 10 / Line 12	14
15				15
16	Weighted Forecast Plant Additions	$ 2,135,619	Summary of HV-LV Plant Additions; Pg 1; Ln 6	16
17				17
18	Forecast Period Capital Addition Revenue Requirements	$ 343,628	Line 14 x Line 16	18
19				19
20	**B. Derivation of Revenue Requirements for Transmission Plant Held for**			20
21	**Future Use During the Forecast Period**			21
22	Forecast Period Transmission Plant Held for Future Use	$ -	Not Applicable in TO4-Cycle 1	22
23				23
24	Cost of Capital Rate $_{(COCR)}$	0.0000%	Not Applicable in TO4-Cycle 1	24
25				25
26	Revenue Requirements for Transmission Plant Held for Future Use	$ -	Line 22 x Line 24	26

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC $_{EU}$)
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO INCENTIVE CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate (AFCR $_{EU-IR-ROE}$) Applicable to**			1
2	**Incentive Weighted Forecast Plant Additions (ROE Incentive Only):**			2
3	PYRR $_{EU-IR-ROE}$ Excluding Franchise Fees and Uncollectible	$ -	Not Applicable in TO4-Cycle 1	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	Total (PYRR $_{EU}$) Excluding FF&U - Adjusted	$ (3,961)	Sum Lines 3 thru 8	9
10				10
11	Gross Electric Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	11
12				12
13	Annual Fix Charge Rate (AFCR $_{EU-IR-ROE}$)	0.0000%	Not Applicable in TO4-Cycle 1	13
14				14
15	Incentive Weighted Forecast Plant Additions	$ -	Not Applicable in TO4-Cycle 1	15
16				16
17	Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-ROE}$)	$ -	Line 13 x Line 15	17
18				18
19	**B. Derivation of Transmission CWIP Incentive Projects Revenue Requirements:**			19
20	Transmission Construction Work In Progress Incentive Projects	$ -	Not Applicable in TO4-Cycle 1	20
21				21
22	Cost of Capital Rate $_{(COCR)}$	0.0000%	Not Applicable in TO4-Cycle 1	22
23				23
24	Transmission CWIP Incentive Projects Revenue Requirements	$ -	Line 20 x Line 22	24

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Base Transmission Revenue Requirements ($BTRR_{EU}$)
For the Rate Effective Period September 1, 2013 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. End Use Customer Base Transmission Revenue Requirement ($BTRR_{EU}$):**			1
2				2
3	End of Prior Year Revenues ($PYRR_{EU}$) Excluding FF&U	$ 307,885	Statement BK-1; Page 1; Line 35	3
4				4
5	Incentive End of Prior Year Revenues ($PYRR_{EU\text{-}IR}$) Excluding FF&U	-	Statement BK-1; Page 1; Line 46	5
6				6
7	Sub-Total Base Period Revenues	$ 307,885	Sum Lines 3 thru 5	7
8				8
9	True-Up Period Adjustment	$ -	Not Applicable in TO4-Cycle 1	9
10				10
11	Interest True-Up Adjustment	-	Not Applicable in TO4-Cycle 1	11
12				12
13	Sub-Total True-Up Adjustments	$ -	Sum Lines 9 thru 11	13
14				14
15	**B. Annual Fixed Charges Applicable to Capital Projects:**			15
16				16
17	Forecast Period Capital Addition Revenue Requirements	$ 343,628	Statement BK-1; Page 4, Line 18	17
18				18
19	Revenue Requirements for Transmission Plant Held for Future Use	-	Statement BK-1; Page 4, Line 26	19
20				20
21	Sub-Total Revenue Requirements for Capital Projects	$ 343,628	Sum Lines 17 thru 19	21
22				22
23	**C. Incentive Transmission CWIP Revenue Requirements**			23
24				24
25	Transmission CWIP Incentive Projects Revenue Requirements	$ -	Statement BK-1; Page 5, Line 24	25
26				26
27	**D. Annual Fixed Charges Applicable to Incentive Capital Projects:**			27
28				28
29	Forecast Period Incentive Capital Additions Revenues ($FC_{EU\text{-}IR\text{-}ROE}$)	$ -	Statement BK-1; Page 5, Line 17	29
30				30
31	**E. Subtotal $BTRR_{EU}$ Excluding FF&U:**	$ 651,513	Sum Lines 7; 13; 21; 25; 29	31
32				32
33	Transmission Related Municipal Franchise Fees Expenses	6,694	Line 31 x 1.0275%	33
34	Transmission Related Uncollectible Expense	919	Line 31 x 0.141%	34
35				35
36	**F. Total Retail $BTRR_{EU}$ With FF&U:**	$ 659,126	Sum Lines 31 thru 34	36

San Diego Gas & Electric Company
Plant Weighting Used in SDG&E's TO4 Formula

Line No	A Electric Function	B Plant Weighting	C Volume
1	Steam Production	13 Month Average of Plant Costs	Volume 5 tab AD
2	Nuclear Production	13 Month Average of Plant Costs	Volume 5 tab AD
3	Other Production	13 Month Average of Plant Costs	Volume 5 tab AD
4	Transmission	13 Month Average of Plant Costs	Volume 5 tab AD
5	Distribution	Average of Beginning and End of Year Plant Costs	Volume 5 tab AD
6	General Plant	Average of Beginning and End of Year Plant Costs	Volume 5 tab AD
7	Common Plant	Average of Beginning and End of Year Plant Costs	Volume 5 tab AD

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AD
Cost of Plant
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No		Amount	Reference	Line No
1	Transmission Electric Miscellaneous Intangible Plant [1,2]	$ 5,982	Stmnt AD WP; Page-AD1; Line 1	1
2				2
3	Total Steam Production Plant	440,146	Stmnt AD WP; Page-AD1; Line 3	3
4				4
5	Total Nuclear Production Plant	1,462,374	Stmnt AD WP; Page-AD1; Line 5	5
6				6
7	Total Hydraulic Production Plant	-	Stmnt AD WP; Page-AD1; Line 7	7
8				8
9	Total Other Production Plant	399,705	Stmnt AD WP; Page-AD1; Line 9	9
10				10
11	Total Production Plant and Intangible Plant	$ 2,308,207	Sum Lines 1 thru 9	11
12				12
13	Total Distribution Plant	$ 4,752,127	Stmnt AD WP; Page-AD1; Line 13	13
14				14
15	Transmission Plant [3]	$ 1,785,708	Stmnt AD WP; Page-AD1; Line 15	15
16				16
17	Transmission Incentive Plant [4]	-	Stmnt AD WP; Page-AD1; Line 17	17
18				18
19	Total Transmission Plant	$ 1,785,708	Sum Lines 15; 17	19
20				20
21	Total General Plant [1]	$ 202,109	Stmnt AD WP; Page-AD1; Line 21	21
22				22
23	Total Common Plant [1]	$ 470,816	Stmnt AD WP; Page-AD1; Line 23	23
24				24
25	Total Plant in Service	$ 9,518,968	Sum Lines 11; 13; 19; 21; 23	25
26				26
27	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	27
28				28
29	Transmission Electric Miscellaneous Intangible Plant	$ 5,982	See Line 1 Above	29
30				30
31	Transmission Plant	1,785,708	See Line 19 Above	31
32				32
33	Transmission Related General Plant	29,185	Line 21 x Line 27	33
34				34
35	Transmission Related Common Plant	67,986	Line 23 x Line 27	35
36				36
37	Transmission Related Total Plant in Service	$ 1,888,861	Sum Lines 29; 31; 33; 35	37
38				38
39	Transmission Plant Allocation Factor [5]	19.84%	Line 37 / Line 25	39

NOTES:

1. Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "seven-factor guideline adjustment" because there's no transfer of transmission or distribution plant among these categories.
2. Transmission Electric Miscellaneous Intangible Plant consist of the great majority of this plant being directly assigned to transmission and is not subject to labor ratio.
3. The amounts stated above are ratemaking utility plant in service and a result of implementing the "seven-factor guideline adjustment" which reflects transfers between generation and distribution functions. See workpaper pages AD-9 and AD-10.
4. The purpose of this footnote is to indicate for incentive projects, the cost of the project, and the in-service-date of incentive projects. There were no incentive projects included in Cycle 1 of SDG&E's TO-4 transmission rate case filing.
5. Used to allocate all elements of working capital, other than working cash.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AE
Accumulated Depreciation and Amortization
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Plant Accumulated Depreciation Reserve [1]	$ 528,768	Stmnt AE WP; Page-AE1; Line 1	1
2				2
3	Incentive Transmission Plant Accumulated Depreciation Reserve	-	Stmnt AE WP; Page-AE1; Line 3	3
4				4
5	Total Transmission Accumulated Depreciation Reserve	$ 528,768	Sum Lines 1; 3	5
6				6
7	Transmission Electric Miscellaneous Intangible Plant Amortization Reserve [2, 3]	$ 4,948	Stmnt AE WP; Page-AE1; Line 7	7
8				8
9	General Plant Accumulated Depreciation Reserve [2]	$ 87,260	Stmnt AE WP; Page-AE1; Line 9	9
10				10
11	Common Plant Accumulated Depreciation Reserve [2]	$ 242,587	Stmnt AE WP; Page-AE1; Line 11	11
12				12
13	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	13
14				14
15	Transmission Related General Plant Accumulated Depreciation Reserve	$ 12,600	Line 9 x Line 13	15
16				16
17	Transmission Related Common Plant Accumulated Depreciation Reserve	$ 35,030	Line 11 x Line 13	17
18				18
19	Total Transmission Related Accumulated Depreciation Reserve	$ 581,346	Sum Lines 5; 7; 15; 17	19

NOTES:

1 The amounts stated above are ratemaking utility plant in service and a result of implementing the "seven-factor guideline adjustment" which reflects transfers between generation and distribution functions.

2 Electric Miscellaneous Intangible Plant, General Plant, and Common Plant are not affected by the "seven-factor guideline adjustment" because there's no transfer of transmission or distribution plant among these categories.

3 Transmission Electric Miscellaneous Intangible Plant consist of the great majority of this plant being directly assigned to transmission and is not subject to labor ratio.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AF
Deferred Credits
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Plant Related ADIT- Excluding Bonus Depreciation	$ (151,843)	Stmnt AF WP; Page-AF1; Line 1	1
2				2
3	Transmission Plant Related ADIT from Bonus Depreciation	(32,324)	Stmnt AF WP; Page-AF1; Line 3	3
4				4
5	Total Transmission Plant Related ADIT	$ (184,167)	Sum Lines 1 thru 3	5
6				6
7	Incentive Transmission Plant Related ADIT	-	Stmnt AF WP; Page-AF1; Line 7	7
8				8
9	Total	$ (184,167)	Sum Lines 5 thru 7	9

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AG
Specified Plant Account (Other than Plant in Service) and Deferred Debits
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No		Amounts	Reference	Line No
1	Transmission Plant Held for Future Use [1]	$ 66,487	Stmnt AG WP; Page-AG1; Line 1	1
2				2
3	Total	$ 66,487	Sum Line 1	3

[1] The balances for Transmission Plant Held for Future Use are derived based on a 13-month weighted average balance.
Plant Held for Future Use represents the parcels of land purchased for the Torrey Pines/Sorrento Mesa, Salt Creek and Oceanside substations as well as various landrights acquisitions from the Bureau of Land Management, US Forest Service, and other various agencies for the Sunrise Powerlink.
See workpaper page AG3.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AH
Operation and Maintenance Expenses
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.			Amounts	Reference	Line No.
1	Derivation of Transmission Operation and Maintenance Expense:				1
2	Total Transmission Expenses	$	69,312	Stmnt AH WP; Page-AH1; Line 2	2
3	Less: Account (561.4) - Scheduling, System Control & Dispatch Services		(7,935)	Stmnt AH WP; Page-AH1; Line 3	3
4	Less: Account (561.8) - Reliability, Planning & Standards Development		(1,719)	Stmnt AH WP; Page-AH1; Line 4	4
5	Less: Account (565) - Transmission of Electricity by Others		(5,140)	Stmnt AH WP; Page-AH1; Line 5	5
6	Less: Account (566) - Miscellaneous Transmission Expenses		(1,753)	Stmnt AH WP; Page-AH1; Line 6	6
7	Less: Account (566) - Miscellaneous Transmission Expenses - Wildfire Damages		(1,000)	Stmnt AH WP; Page-AH1; Line 7	7
8	Total Transmission O&M Expenses Incl. Intervener Compensation Costs	$	51,765	Sum Lines 2 thru 7	8
9	Less: CPUC Intervener Funding Expenses (See Statement BK1; Page 1; Line 6)		-	Stmnt AH WP; Page-AH1; Line 9	9
10	Total Transmission O&M Expense (See Statement BK1; Page 1; Line 2)	$	51,765	Sum Lines 8 thru 9	10
11					11
12	Derivation of Administrative and General Expense:				12
13	Total Administrative & General Expenses	$	486,575	Stmnt AH WP; Page-AH1; Line 13	13
14	Adjustments to Per Book A&G expenses:				14
15	Nuclear liability insurance expenses		(879)	Stmnt AH WP; Page-AH1; Line 15	15
16	Damages & Injuries - Wildfire Insurance Premium		(3,167)	Stmnt AH WP; Page-AH1; Line 16	16
17	Damages & Injuries - Wildfire Insurance Premium - Capital Cost Jan to May'11		4,039	Stmnt AH WP; Page-AH1; Line 17	17
18	Damages & Injuries - Wildfire Insurance Premium - Capital Cost Jan to May'12		3,000	Stmnt AH WP; Page-AH1; Line 18	18
19	Damages & Injuries - Wildfire Damage Claims - TO3 Cycle 5		(44,489)	Stmnt AH WP; Page-AH1; Line 19	19
20	Damages & Injuries - Wildfire Damage Claims - TO3 C6 - Capital Cost Jan to Mar '12		13,580	Stmnt AH WP; Page-AH1; Line 20	20
21	Damages & Injuries - Wildfire Damage Claims - TO3 Cycle 6		(159,194)	Stmnt AH WP; Page-AH1; Line 21	21
22	Damages & Injuries - Wildfire Damage Claims - TO4 Cycle 1		4,864	Stmnt AH WP; Page-AH1; Line 22	22
23	CPUC reimbursement fees		(4,632)	Stmnt AH WP; Page-AH1; Line 23	23
24	Litigation expenses - Litigation Cost Memorandum Account (LCMA)		(623)	Stmnt AH WP; Page-AH1; Line 24	24
25	CPUC energy efficiency programs		(10,523)	Stmnt AH WP; Page-AH1; Line 25	25
26	Advanced Metering Infrastructure (AMI) lease facilities		(281)	Stmnt AH WP; Page-AH1; Line 26	26
27	Hazardous substances - Hazardous Substance Cleanup Cost Account		(7)	Stmnt AH WP; Page-AH1; Line 27	27
28	Total Adjusted A&G Expenses Excluding Property Insurance	$	288,263	Sum Lines 13 thru 27	28
29	Property Insurance (Reflected on Line 51 below due to different allocation factor)		(6,143)	Stmnt AH WP; Page-AH1; Line 29	29
30	Total Adjusted A&G Expenses Excluding Property Insurance	$	282,120	Sum Lines 28 and 29	30
31	Transmission Wages and Salaries Allocation Factor		14.44%	Statement AI; Page 1; Line 13	31
32	Total Transmission Related Administrative and General Expense	$	40,738	Line 30 x Line 31	32
33					33
34	Derivation of Transmission Plant Property Insurance Allocation Factor:				34
35	Transmission Plant	$	1,785,708	Statement AD; Page 1; Line 31	35
36	Transmission Related General Plant		29,185	Statement AD; Page 1; Line 33	36
37	Transmission Related Common Plant		67,986	Statement AD; Page 1; Line 35	37
38	Total	$	1,882,879	Sum Lines 35 thru 37	38
39					39
40	Total Transmission Plant	$	1,785,708	Statement AD; Page 1; Line 31	40
41	Total Steam Production Plant		440,146	Statement AD; Page 1; Line 3	41
42	Total Other Production Plant		399,705	Statement AD; Page 1; Line 9	42
43	Total Nuclear Production Plant		-	Not Applicable in Developing Ratio	43
44	Total Distribution Plant		4,752,127	Statement AD; Page 1; Line 13	44
45	Total General Plant		202,109	Statement AD; Page 1; Line 21	45
46	Total Common Plant		470,816	Statement AD; Page 1; Line 23	46
47	Total Plant in Service Excluding SONGS	$	8,050,612	Sum Lines 40 thru 46	47
48					48
49	Transmission Plant Property Insurance Allocation Factor		23.39%	Line 38 / Line 47	49
50					50
51	Total Property Insurance	$	6,143	See Line 29 Above	51
52					52
53	Property Insurance Allocated to Transmission, General, and Common Plant	$	1,437	Line 49 x Line 51	53
54					54
55	Transmission Related A & G Expenses Excluding Property Insurance	$	40,738	See Line 32 Above	55
56					56
57	Transmission Related A & G Expenses Including Property Insurance	$	42,175	Sum Lines 53 & 55	57

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AI
Wages and Salaries
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Production Wages & Salaries	$ 10,458	Stmnt AI WP; Page-AI1; Line 1	1
2				2
3	Transmission Wages & Salaries	17,779	Stmnt AI WP; Page-AI1; Line 3	3
4				4
5	Distribution Wages & Salaries	53,833	Stmnt AI WP; Page-AI1; Line 5	5
6				6
7	Customer Accounts Wages & Salaries	24,230	Stmnt AI WP; Page-AI1; Line 7	7
8				8
9	Customer Services and Informational Wages & Salaries	16,780	Stmnt AI WP; Page-AI1; Line 9	9
10				10
11	Total	$ 123,080	Sum Lines 1 thru 9	11
12				12
13	Transmission Wages and Salaries Allocation Factor	14.44%	Line 3 / Line 11	13

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AJ
Depreciation and Amortization Expense
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Transmission Depreciation Expense	$ 46,762	Stmnt AJ WP; Page-AJ1; Line 1	1
2				2
3	Transmission Incentive Depreciation Expense	-	Stmnt AJ WP; Page-AJ1; Line 3	3
4				4
5	Total Transmission Plant Depreciation Expense	$ 46,762	Sum Lines 1 thru 3	5
6				6
7	Transmission Electric Miscellaneous Intangible Plant Amortization Expense	$ 261	Stmnt AJ WP; Page-AJ1; Line 7	7
8				8
9	General Plant Depreciation Expense	$ 9,082	Stmnt AJ WP; Page-AJ1; Line 9	9
10				10
11	Common Plant Depreciation Expense	$ 44,477	Stmnt AJ WP; Page-AJ1; Line 11	11
12				12
13	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	13
14				14
15	Transmission Related General Plant Depreciation Expense	$ 1,311	Line 9 x Line 13	15
16				16
17	Transmission Related Common Plant Depreciation Expense	$ 6,422	Line 11 x Line 13	17
18				18
19	Total Transmission, Intangible, Gen. and Comm. Depr. & Amort. Exp.	$ 54,756	Sum Lines 1; 7; 15; 17	19
20				20
21	Incentive Transmission, Intangible, Gen. and Comm. Depr. & Amort. Exp.	$ -	Stmnt AJ WP; Page-AJ1; Line 21	21
22				22
23	Valley Rainbow Project Cost Amortization Expense	$ 1,893	Stmnt AJ WP; Page-AJ1; Line 23	23
24				24
25	Transmission Abandoned Project Cost Amortization Expense	$ -	Stmnt AJ WP; Page-AJ1; Line 25	25

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AK
Taxes Other Than Income Taxes
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Total Property Taxes	$ 51,794	Stmnt AK WP; Page-AK1; Line 5	1
2				2
3	Less: SONGS Property Taxes	(4,098)	Stmnt AK WP; Page-AK1; Line 7	3
4				4
5	Property Taxes Less SONGS	$ 47,696	Line 1 Minus Line 3	5
6				6
7				7
8	Derivation of Transmission Related Property Tax Allocation Factor:			8
9	Transmission Plant	$ 1,785,708	Statement AD; Page 1; Line 31	9
10	Transmission Electric Miscellaneous Intangible Plant	-	N/A in Ratio Development	10
11	Transmission Related General Plant	29,185	Statement AD; Page 1; Line 33	11
12	Transmission Related Common Plant	67,986	Statement AD; Page 1; Line 35	12
13	Total	$ 1,882,879	Sum Lines 9 thru 12	13
14				14
15	Total Nuclear Plant	$ -	N/A in Ratio Development	15
16	Total Steam Plant	440,146	Statement AD; Page 1; Line 3	16
17	Total Other Production Plant	399,705	Statement AD; Page 1; Line 9	17
18	Total Transmission Plant	1,785,708	Statement AD; Page 1; Line 31	18
19	Total Transmission Electric Miscellaneous Intangible Plant	-	N/A in Ratio Development	19
20	Total Distribution Plant	4,752,127	Statement AD; Page 1; Line 13	20
21	Total General Plant	202,109	Statement AD; Page 1; Line 21	21
22	Total Common Plant	470,816	Statement AD; Page 1; Line 23	22
23	Total Investment in Plant Excluding SONGS	$ 8,050,612	Sum Lines 15 thru 22	23
24				24
25	Transmission Related Property Tax Allocation Factor	23.39%	Line 13 / Line 23	25
26				26
27	Transmission Related Property Taxes Expense	$ 11,156	Line 5 x Line 25	27
28				28
29				29
30	Payroll Taxes	$ 14,060	Stmnt AK WP; Page-AK1; Line 16	30
31				31
32	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	32
33				33
34	Transmission Related Payroll Taxes Expense	$ 2,030	Line 30 x Line 32	34

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AL
Working Capital
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts		Reference	Line No.
1	Plant Materials and Operating Supplies [a]	$	56,843	Stmnt AL WP; Page-AL1; Line 1	1
2					2
3	Transmission Plant Allocation Factor		19.84%	Statement AD; Line 39	3
4					4
5	Transmission Related Materials and Supplies	$	11,278	Line 1 x Line 3	5
6					6
7	Prepayments [a]	$	31,412	Stmnt AL WP; Page-AL1; Line 7	7
8					8
9	Transmission Related Prepayments	$	6,232	Line 3 x Line 7	9
10					10
11	Derivation of Transmission Related Cash Working Capital:				11
12	Transmission Operation & Maintenance Expense	$	51,765	Stmnt AH WP; page AH1; Line 8	12
13	Transmission Related Administrative & General Expenses		42,175	Stmnt AH WP; page AH1; Line 57	13
14	Intervenor Compensation Expenses		-	Stmnt AH WP; page AH1; Line 9	14
15	Total	$	93,940	Sum Lines 12 thru 14	15
16					16
17	One Eighth O&M Method		12.50%	FERC Method = 1/8 of O&M	17
18					18
19	Transmission Related Cash Working Capital - Retail Customers	$	11,743	Line 15 x Line 17	19
20					20
21	Transmission Related Cash Working Capital - Wholesale Customers	$	11,743	[(Line 12 + Line 13) x Line 17]	21

[a] The balances for Materials & Supplies and Prepayments are derived based on a 13-month weighted average balance. This is the same method used in TO3.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AQ
Federal Income Tax Deductions, Other Than Interest
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	South Georgia Income Tax Adjustment	$ 2,333	Stmnt AQ WP; Page-AQ1; Line 1	1

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AR
Federal Tax Adjustments
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Transmission Related Amortization of Investment Tax Credits	$ (265)	Stmnt AR WP; Page-AR1; Line 1	1
2				2
3	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Stmnt AR WP; Page-AR1; Line 3	3
4				4
5	Total	$ (265)	Sum Lines 1 thru 3	5

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AU
Revenue Credits
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	(451) Miscellaneous Service Revenues	$ -	Stmnt AU WP; Page-AU1; Line 1	1
2				2
3	(453) Sales of Water and Water Power	-	Stmnt AU WP; Page-AU1; Line 3	3
4				4
5	(454) Rent from Electric Property	588	Stmnt AU WP; Page-AU1; Line 5	5
6				6
7	(455) Interdepartmental Rents	-	Stmnt AU WP; Page-AU1; Line 7	7
8				8
9	(456) Other Electric Revenues	2,064	Stmnt AU WP; Page-AU1; Line 9	9
10				10
11	Transmission Related Revenue Credits	$ 2,652	Sum Lines 1 thru 9	11
12				12
13	(411.6 & 411.7) Gain or Loss From Sale of Plant Held for Future Use	$ -	Stmnt AU WP; Page AU1; Line 13	13

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Long-Term Debt Component - Denominator:			1
2	(Plus): Account 221 - Bonds	$ 3,536,905	Stmnt AV WP; Page-AV1; Line 2	2
3	(Less): Account 222 - Reacquired Bonds	-	Stmnt AV WP; Page-AV1; Line 3	3
4	(Plus): Account 224 - Other Long-Term Debt (Acct. 224)	253,720	Stmnt AV WP; Page-AV1; Line 4	4
5	(Plus): Account 225 - Unamortized Premium on Long-Term Debt	-	Stmnt AV WP; Page-AV1; Line 5	5
6	(Less): Account 226 - Unamortized Discount on Long-Term Debt-Debit	12,055	Stmnt AV WP; Page-AV1; Line 6	6
7	Total Long Term Debt (LTD)	$ 3,778,570	Line 2 Minus Line 3 Plus Lines 4 & 5 Minus Line 6	7
8				8
9	Long-Term Debt Component - Numerator:			9
10	(Plus): Account 427 - Interest on Long-Term Debt	$ 163,736	Stmnt AV WP; Page-AV1; Line 10	10
11	(Plus): Account 428 - Amort. of Debt Disc. and Expense	2,607	Stmnt AV WP; Page-AV1; Line 11	11
12	(Plus): Account 428.1 - Amortization of Loss on Reacquired Debt	3,388	Stmnt AV WP; Page-AV1; Line 12	12
13	(Less): Account 429 - Amort. of Premium on Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 13	13
14	(Less): Account 429.1 - Amortization of Gain on Reacquired Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 14	14
15	Total LTD Interest = (i)	$ 169,731	Sum Lines 10; 11; 12 Minus Lines 13 & 14	15
16				16
17	Cost of Long-Term Debt:	4.49%	Line 15 / Line 7	17
18				18
19				19
20	Preferred Equity Component:			20
21	PF = Preferred Stock - Account 204	$ 78,475	Stmnt AV WP; Page-AV1; Line 21	21
22	d(pf) = Total Dividends Declared-Preferred Stocks - Account 437	$ 4,820	Stmnt AV WP; Page-AV1; Line 22	22
23	Cost of Preferred Equity	6.14%	Line 22 / Line 21	23
24				24
25				25
26	Common Equity Component:			26
27	Proprietary Capital	$ 3,990,776	Stmnt AV WP; Page-AV1; Line 27	27
28	(Less): Account 204 Preferred Stock	78,475	Stmnt AV WP; Page-AV1; Line 28	28
29	(Less): Account 216.1 Unappropriated Undistributed Subsidiary Earnings	-	Stmnt AV WP; Page-AV1; Line 29	29
30	CS = Common Stock	$ 3,912,301	Line 27 Minus Lines 28 & 29	30
31				31

Line No.		(a) Amount	(b) Cap. Struct. Ratio	(c) Cost of Capital	(d) = (b) x (c) Weighted Cost of Capital	Reference	Line No.
32	Return on Common Equity				**11.30%**	Stmnt AV WP; Page-AV1; Line 32	32
33		(a)	(b)	(c)	(d) = (b) x (c)		33
34			Cap. Struct.	Cost of	Weighted		34
35	Weighted Cost of Capital:	Amount	Ratio	Capital	Cost of Capital		35
36							36
37	Long-Term Debt	$ 3,778,570	48.63%	4.49%	2.18%	Col. C = Line 17 Above	37
38	Preferred Equity	78,475	1.01%	6.14%	0.06%	Col. C = Line 23 Above	38
39	Common Equity	3,912,301	50.36%	11.30%	5.69%	Col. C = Line 32 Above	39
40	Total Capital	$ 7,769,346	100.00%		7.93%	Sum Lines 37 thru 39	40
41							41
42							42
43	Cost of Equity Component (Preferred & Common):				5.75%	Sum Lines 38; 39	43
44							44

Line No.		(a) Amount	(b) Cap. Struct. Ratio	(c) Cost of Capital	(d) = (b) x (c) Weighted Cost of Capital	Reference	Line No.
45	Incentive Return on Common Equity				**0.00%**	Not Applicable in TO4-Cycle 1	45
46		(a)	(b)	(c)	(d) = (b) x (c)		46
47			Cap. Struct.	Cost of	Weighted		47
48	Weighted Cost of Capital:	Amount	Ratio	Capital	Cost of Capital		48
49							49
50	Long-Term Debt	$ 3,778,570	48.63%	0.00%	0.00%	Not Applicable in TO4-Cycle 1	50
51	Preferred Equity	78,475	1.01%	0.00%	0.00%	Not Applicable in TO4-Cycle 1	51
52	Common Equity	3,912,301	50.36%	0.00%	0.00%	Not Applicable in TO4-Cycle 1	52
53	Total Capital	$ 7,769,346	100.00%		0.00%	Sum Lines 50 thru 52	53
54							54
55							55
56	Cost of Equity Component (Preferred & Common):				0.00%	Sum Lines 51; 52	56

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Cost of Capital Rate $_{(COCR)}$ Calculation:			1
2				2
3	a) Federal Income Tax Component:			3
4				4
5	Where:			5
6	A = Sum of Preferred Stock and Return on Equity Component	5.75%	Statement AV; Page 13; Line 43	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$ 265	Statement AR; Page 11; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$ -		8
9	D = Transmission Rate Base	$ 1,219,088	Statement BK1; Page 2; Line 26	9
10	FT = Federal Income Tax Rate July 1, 2011	35%	Federal Income Tax Rate	10
11				11
12	Federal Income Tax = $\frac{(A + [(C - B) / D]) (FT) =}{1 - FT}$	3.0844%	Federal Income Tax Expense	12
13				13
14				14
15				15
16	b) State Income Tax Component:			16
17				17
18	Where:			18
19	A = Sum of Preferred Stock and Return on Equity Component	5.75%	Statement AV; Page 13; Line 43	19
20	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$ 265	Statement AR; Page 11; Line 5	20
21	C = Equity AFUDC Component of Transmission Depreciation Expense	$ -		21
22	D = Transmission Rate Base	$ 1,219,088	Statement BK1; Page 2; Line 26	22
23	FT = Federal Income Tax Expense	3.0844%	Line 12 Above	23
24	ST = State Income Tax Rate July 1, 2011	8.84%	State Income Tax Rate	24
25				25
26	State Income Tax = $\frac{(A + [(C - B) / D] + \text{Federal Income Tax}) (ST) =}{1 - ST}$	0.8546%	State Income Tax Expense	26
27				27
28				28
29	c) Total Federal & State Income Tax Expense:	3.9390%	Sum Lines 12; 26	29
30				30
31	d) Total Weighted Cost of Capital:	7.9300%	Statement AV; Page 13; Line 40	31
32				32
33	e) Cost of Capital Rate $_{(COCR)}$:	11.8690%	Sum Lines 29; 31	33

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.			Reference	Amounts	Line No.
1	Incentive Cost of Capital Rate $_{(ICOCR)}$ Calculation:				1
2					2
3	a) Federal Income Tax Component:				3
4					4
5	Where:				5
6	A = Sum of Preferred Stock and Return on Equity Component		0.00%	Statement AV; Page 13; Line 56	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		8
9	D = Incentive Transmission Rate Base	$	-	Statement BK1; Page 2; Line 39	9
10	FT = Federal Income Tax Rate July 1, 2011		35%	Federal Income Tax Rate	10
11					11
12	Federal Income Tax = (A + [(C - B) / D]) (FT) =		0.0000%	Federal Income Tax - Not Applicable in TO4-Cycle 1	12
13	1 - FT				13
14					14
15					15
16	b) State Income Tax Component:				16
17					17
18	Where:				18
19	A = Sum of Preferred Stock and Return on Equity Component		0.00%	Statement AV; Page 13; Line 56	19
20	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	20
21	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		21
22	D = Incentive Transmission Rate Base	$	-	Statement BK1; Page 2; Line 39	22
23	FT = Federal Income Tax Expense		0.0000%	Statement AV WP; Page AV3; Line 12	23
24	ST = State Income Tax Rate July 1, 2011		8.84%	State Income Tax Rate	24
25					25
26	State Income Tax = (A + [(C - B) / D] + Federal Income Tax) (ST) =		0.0000%	State Income Tax - Not Applicable in TO4-Cycle 1	26
27	1 - ST				27
28					28
29	c) Total Federal & State Income Tax Expense:		0.0000%	Sum Lines 12; 26	29
30					30
31	d) Total Weighted Cost of Capital:		0.0000%	Statement AV; Page 13; Line 53	31
32					32
33	e) Incentive Cost of Capital Rate $_{(ICOCR)}$:		0.0000%	Sum Lines 29; 31	33

SAN DIEGO GAS AND ELECTRIC COMPANY
Electric Transmission O&M Expenses
12 Months Ending May 31, 2012
($1,000)

Line No.	FERC Acct	Description	(a) Total Per Books	(b) Excluded Expenses	(c) = (a) + (b) Total Adjusted	Reference	Line No.
1		***Electric Transmission Operations***					1
2	560	Operation Supervision and Engineering	$ 7,534	$ -	$ 7,534		2
3	561.1	Load Dispatch - Reliability	457	-	457		3
4	561.2	Load Dispatch - Monitor and Operate Transmission System	2,595	-	2,595		4
5	561.3	Load Dispatch - Transmission Service and Scheduling	-	-	-		5
6	561.4	Scheduling, System Control and Dispatch Services	7,935	(7,935)	-		6
7	561.5	Reliability, Planning and Standards Development	-	-	-		7
8	561.6	Transmission Service Studies	-	-	-		8
9	561.7	Generation Interconnection Studies	-	-	-		9
10	561.8	Reliability, Planning and Standards Development Services	1,719	(1,719)	-		10
11	562	Station Expenses	2,202	-	2,202		11
12	563	Overhead Line Expenses **(a)**	5,557	-	5,557		12
13	564	Underground Line Expenses	-	-	-		13
14	565	Transmission of Electricity by Others	5,140	(5,140)	-		14
15	566	Misc. Transmission Expenses	11,488	(1,753)	9,735		15
16	566	Misc. Transmission Expenses - Wildfire Damages **(b)**	1,000	(1,000)	-		16
17	567	Rents	1,907	-	1,907		17
18		*Total Operation*	$ 47,534	$ (17,547)	$ 29,987	Sum Lines 2 thru 17	18
19							19
20		***Electric Transmission Maintenance***					20
21	568	Maintenance Supervision and Engineering	1,029	-	1,029		21
22	569	Maintenance of Structures	-	-	-		22
23	569.1	Maintenance of Computer Hardware	1,414	-	1,414		23
24	569.2	Maintenance of Computer Software	1,734	-	1,734		24
25	569.3	Maintenance of Communication Equipment	-	-	-		25
26	569.4	Maintenance of Misc. Regional Transmission Plant	127	-	127		26
27	570	Maintenance of Station Equipment	6,121	-	6,121		27
28	571	Maintenance of Overhead Lines	11,091	-	11,091		28
29	572	Maintenance of Underground Lines	116	-	116		29
30	573	Maintenance of Misc. Transmission Plant	146	-	146		30
31		*Total Maintenance*	$ 21,778	$ -	$ 21,778	Sum Lines 21 thru 30	31
32							32
33		**Total Transmission O&M Expenses**	**$ 69,312**	**$ (17,547)**	**$ 51,765**	Line 18 + Line 31	33
34							34
35							35
36	**Excluded Expenses (recovery method in parentheses)**						36
37	561.4	Scheduling, System Control and Dispatch Services (ERRA)		$ (7,935)			37
38	561.8	Reliability, Planning and Standards Development Services (ERRA)		(1,719)			38
39	565	Transmission of Electricity by Others (ERRA)		(5,140)			39
40	566	Misc. Transmission Expenses:					40
41		ISO Grid Management Costs (ERRA)	$ (3,690)				41
42		Reliability Services (RS rates)	2,185				42
43		Other (TRBAA, TACBAA)	(248)				43
44		Total Excluded Misc. Transmission Expenses		(1,753)			44
45	566	Misc. Transmission Expenses - Wildfire Damages (b)		(1,000)			45
46	**Total Excluded Expenses**			**$ (17,547)**			46
47							47
48	**(a)**	Other OH Line Expenses - $2,507K plus Sunrise Fire Mitigation cost - $3,050K = Total $5,557K. The Sunrise fire mitigation cost					48
49		that was paid in April 2012 was not capitalized pursuant to the TO3 Cycle 6 FERC settlement in ER 12-2454.					49
50							50
51	**(b)**	In April 2011, Acct 566 was credited by $1M, and was subsequently debited in June 2011 by the same $1M to reverse the original entry.					51
52		Both entries dealt with the issue of whether or not SDG&E was able to directly assign wildfire expenses to Acct 566, which the FERC					52
53		disallowed in its Letter Order in Docket No. ER10-2235-000, dated 10/8/2010 (133 FERC ¶ 61,016). Since the base period for the					53
54		TO4-Cycle 1 filing is for the 12-month period June 2011 - May 2012, total O&M expense includes the $1M charge in June 2011,					54
55		which must be removed to normalize the base period O&M expense.					55
56							56

SAN DIEGO GAS AND ELECTRIC COMPANY
Administrative & General Expenses
12 Months Ending May 31 2012
($1,000)

Line No.	FERC Acct	Description	(A) Total Per Books	(B) Other Adjustment [1]	(C) Wildfire Capital Cost [2] Jan - May'11	(D) Wildfire Capital Cost [3a, 3b, 3c] Jan - May'12	(E) = (∑ A to D) Adjusted Per Books	(F) Excluded Expenses	(G) = (E) + (F) Total Adjusted	Reference	Line No.
1		***Administrative & General***									1
2	920	A&G Salaries	$ 19,700				$ 19,700	$ -	$ 19,700		2
3	921	Office Supplies & Expenses	7,242				7,242	-	7,242		3
4	922	Less Construction Transfer	(7,831)				(7,831)	-	(7,831)		4
5	923	Outside Services	56,883				56,883	-	56,883		5
6	924	Property Insurance	6,143				6,143	-	6,143		6
7	925	Damages & Injuries - Non Wildfire Related [4]	12,458				12,458	(879)	11,579		7
8	925	Damages & Injuries - Wildfire Insurance Premium [2, 3a]	72,166		(3,167)	4,039	73,038	-	73,038		8
9	925	Damages & Injuries - Wildfire Damage Claims - TO3 Cycle 5 [1]	41,489	3,000			44,489	(44,489)	-		9
10	925	Damages & Injuries - Wildfire Damage Claims - TO3 Cycle 6 [3b,]	145,614			13,580	159,194	(159,194)	-		10
11	925	Damages & Injuries - Wildfire Damage Claims - TO4 Cycle 1 [3c]	27,931			4,864	32,795	-	32,795		11
12	926	Employee Pension & Benefits	60,000				60,000	(787)	59,213		12
13	927	Franchise Expenses	-				-	-	-		13
14	928	Regulatory Expenses	13,865				13,865	(5,255)	8,610		14
15	929	Company Energy Use	(1,858)				(1,858)	-	(1,858)		15
16	930	Misc. General Expenses	15,786				15,786	(9,736)	6,050		16
17	931	Rents	9,182				9,182	(281)	8,901		17
18	935	Maintenance of General Plant	7,805				7,805	(7)	7,798		18
19											19
20		**Total Administrative & General Expenses**	**$ 486,575**	**$ 3,000**	**$ (3,167)**	**$ 22,483**	**$ 508,891**	**$ (220,628)**	**$ 288,263**	Sum Lines 2 thru 18	20
21											21
22											22
23	**Excluded Expenses:**										23
24	925	Nuclear liability insurance expenses							$ (879)		24
25	925	Damages & Injuries - Wildfire Damage Claims applicable to TO3 Cycle 5 [1]							(44,489)		25
26	925	Damages & Injuries - Wildfire Damage Claims applicable to TO3 Cycle 6 [5]							(159,194)		26
27	928	CPUC reimbursement fees						$ (4,632)			27
28	928	Litigation expenses - Litigation Cost Memorandum Account (LCMA)						(623)	(5,255)		28
29	926	CPUC energy efficiency programs						$ (787)			29
30	930	CPUC energy efficiency programs						(9,736)	(10,523)		30
31	931	Advanced Metering Infrastructure (AMI) lease facilities							(281)		31
32	935	Hazardous Substances-Hazardous Substance Cleanup Cost Account							(7)		32
33		Total							**$ (220,628)**		33
34											34

Footnotes:

[1] In Feb, 2011, $3M was debited to Acct 925 for the wildfire damage claims. This was subsequently reversed and credited in June 2011. Since the TO4-Cycle 1 filing base period covers June 2011 to May 2012 the adjustment was added back to normalize A&G expense. The total wildfire damage claims incurred in TO3 Cycle 5 at $44.489M is excluded since it was previously recovered in a prior cyclical filing.

[2] In the Letter Order (140 FERC ¶ 61,018) for FERC docket ER11-4318, the FERC denied the capitalization of wildfire insurance premiums and damages claims. As a result, an adjusting entry was made in December 2011 expensing wildfire costs capitalized from January - May 2011. To normalize A&G expense for the TO4-Cycle 1 base period, the $3.167M is reversed and excluded from A&G expense.

[3a] In the Letter Order (140 FERC ¶ 61,018) for FERC docket ER11-4318, the FERC denied the capitalization of wildfire insurance premiums and damages claims. As a result, an adjusting entry was made in September 2012 to expense wildfire premiums that were capitalized from January - May 2012. To normalize A&G expense for the TO4-Cycle 1 base period, the $4.039M is added to A&G expense because it pertains to January - May 2012, not September 2012.

[3b] In the September 2012 adjusting entry to expense capitalized wildfire costs, it also included TO3-Cycle 6 wildfire damage claims from January - May 2012. In order to normalize A&G expense for the TO4-Cycle 1 base period, the $13.580M is added to A&G expense because it pertains to January - May 2012, not September 2012.

[3c] To the extent the September 2012 adjusting entry to expense capitalized wildfire costs also included TO4-Cycle 1 wildfire damage from claims of $4.864M January - May 2012, in order to normalize A&G expense for the TO4-Cycle 1 base period, the $4.864M is added to A&G expense because it pertains to January - May 2012, not September 2012.

[4] FERC Acct 925 is shown in five parts to reflect non-wildfire related, wildfire insurance premium, and wildfire damage claims separately.

[5] The amounts reported for the wildfire damage claims for TO3 Cycle 6 was $159,194K and is excluded in this filing.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Lolit P. Tanedo, being duly sworn, on oath, says that she is the Lolit P. Tanedo identified in the foregoing prepared direct testimony; that she prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers would, under oath, be the same.

Lolit P. Tanedo
____
Lolit P. Tanedo

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, ANNIE VICTORIA RUIZ, a Notary Public, personally appeared Lolit P. Tanedo, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that she executed the same in her authorized capacity, and that by her signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Annie Victoria Ruiz
____

ANNIE VICTORIA RUIZ
COMM. #1877490
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jan 18, 2014
ST01 ST01

Exhibit No. SDG-5

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
MICHELLE SOMERVILLE
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-5

#274424

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
MICHELLE SOMERVILLE
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name, position and place of employment.

A1. My name is Michelle Somerville, and I am the Regulatory Accounting Manager for San Diego Gas & Electric Company (SDG&E). My business address is 101 Ash Street, San Diego, CA 92101.

Q2. Please summarize your higher education.

A2. I received a Bachelor's in Business Administration degree with an emphasis in accounting as well as a Masters in Professional Accounting from the University of Texas at Austin in 1992. I have been a Certified Public Accountant (CPA), licensed in the State of Texas, since 1994.

Q3. Please describe your current responsibilities as well as prior experience before coming to SDG&E.

A3. I have been employed with SDG&E and Sempra Energy since 2000. My current responsibilities include maintaining SDG&E's FERC accounting records and general ledger and coordinating all FERC Form 1, Form 2 and related reporting. In addition to my current position in Regulatory Accounting, I served as the Regulatory Accounts Manager at SDG&E, the Capital Asset Management Supervisor at SDG&E as well as several budgetary roles within the utility. I began my career at Sempra Energy in the Internal Audit Department. During my career at SDG&E, I have testified several times before the California Public Utilities Commission (CPUC) in cases involving the use of

Regulatory Accounts for ratemaking purposes. Prior to 2000, I worked for Baker Hughes Inc. first in the Internal Audit Department and then as a Finance Manager for the pumping division, Centrilift, responsible for the finance and accounting for operations in California and Alaska. Prior to that, I worked at Ernst & Young as an auditor.

II. PURPOSE OF TESTIMONY

Q4. What is the purpose of your testimony?

A4. The purpose of my testimony is twofold. First, I will explain and support the way in which the TO4 Formula accounts for certain categories of electric Administrative & General (A&G) Costs. Specifically, SDG&E proposes to modify Appendix VIII to address the treatment of electric costs booked to FERC Account Nos. 920-935, Administrative and General Expense - Electric. Under the TO3 Formula, all costs booked to those accounts were assigned to either Transmission or Distribution using a labor allocation factor. In contrast, the TO4 Formula incorporates a bifurcated approach that permits SDG&E (1) to allocate costs that cannot be directly assigned to a specific function using a labor allocation factor (similar to TO3) and/or (2) directly assign costs to a business segment or division, where it is appropriate to do so, consistent with cost causation principles.

Second, I will explain SDG&E's proposed modification to Appendix VIII to address Electric Miscellaneous Intangible Plant. Specifically, the TO3 Formula allocated Electric Intangible Plant using a labor allocation factor. The TO4 Formula allows SDG&E either to allocate Electric Intangible Plant using a labor ratio or to directly assign intangible plant costs, consistent with cost causation principles.

Q5. Please indicate the different sections in your testimony.

A5. The different sections in my testimony are as follows:

I. Introduction

II. Purpose of Testimony

III. Proposed Direct Assignment of Certain Expenses Booked to Accounts 920-935

IV. Proposed Direct Assignment of Certain Costs Booked to Miscellaneous Intangible Plant

III. PROPOSED DIRECT ASSIGNMENT OF CERTAIN EXPENSES BOOKED TO ACCOUNTS 920-935

Q6. How has SDG&E revised Appendix VIII to address the direct assignment issues discussed above?

A6. SDG&E has revised Section ___of Appendix VIII to read as follows:

> 2. Administrative and General Expense (A&G)-Electric shall equal SDG&E's expenses recorded in FERC Account Nos. 920-935, excluding FERC Account No. 930.1 (General Advertising Expense). These expenses shall be either (a) allocated across applicable functions based on the use of the Transmission Wages and Salaries Allocation Factor and/or (b) directly assigned to the relevant function where: (i) direct assignment is consistent with cost causation principles, (ii) the relationship between cost incurrence and cost responsibility is obvious and reviewable and (iii) direct assignment is reasonable and cost allocation is unreasonable, *e.g.*, it would be unreasonable to use a labor ratio to allocate costs to both distribution and transmission functions where the costs at issue have been affirmatively linked to only transmission or distribution. The dollar threshold for direct assignment shall be $5 Million per event for Account 925 expenses and $1 Million per event for expenses related to the other referenced A&G accounts.

In this manner, SDG&E will ensure that it follows cost causation principles and objective factors in determining whether and to what extent it should allocate A&G costs using a labor allocator or directly assign costs in specified situations where use of a labor ratio allocator would be unreasonable.

Q7. How exactly will this bifurcated approach operate in practice?

A7. SDG&E is proposing that where (1) costs or expenses recorded to the relevant account are related to an identifiable, significant event and (2) the event pertains solely to the transmission function, as opposed to the distribution function, SDG&E should be permitted to directly assign those costs to its transmission function. All other costs recorded to the A&G accounts that do not lend themselves to direct assignment would be allocated on the basis of Transmission Wages and Salaries Allocation Factor (labor ratio) to all of SDG&E's functions. More specifically, for tariff purposes, amounts recorded in the A&G Accounts will consist of two buckets: Bucket 1 will include costs that SDG&E deems directly assignable and Bucket 2 will include all other amounts recorded in the relevant accounts. The amounts in Bucket 2 will be allocated across all functions on the basis of a labor ratio as mentioned above and the amounts in Bucket 1 will be directly assigned to the function, *e.g.*, transmission function based on cost causation principles. This bifurcated approach balances the Commission's policy preference for labor based allocation of A&G costs with situations where the causation is so clear that only direct assignment will result in just and reasonable rates under the Commission's cost causation principles. Regardless of which method is used for assignment, *all* costs recorded in these Accounts would remain subject to stakeholder comment and Commission review as is the case under the TO3 Formula.

Q8. The proposed modification to Appendix VIII discussed above refers to "cost causation" principles. What do you mean by "cost causation" principles?

A8. The "*fundamental* theory of Commission ratemaking is that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred."[1] A labor allocation ratio may be appropriate for allocating many types of A&G costs across all affected business units, but not in the circumstance of a major cost linked directly to transmission operations. That is what the direct assignment option is intended to address.

IV. PROPOSED DIRECT ASSIGNMENT OF CERTAIN COSTS BOOKED TO MISCELLANEOUS INTANGIBLE PLANT

Q9. On line 1 of Statement AD in Volume 4 you show Electric Miscellaneous Intangible Plant allocated to transmission service. For TO4 are you allocating this plant similarly to the A&G proposal discussed above and is this a deviation from the TO3 Formula?

A9. Yes to both questions. In TO3, SDG&E allocated all electric intangible plant using a labor ratio. In this TO4 Formula, SDG&E is proposing a bifurcated approach that provides for allocation or direct assignment, as appropriate, similar to the above proposed allocation of electric A&G but without any threshold amounts. Permitting direct assignment of electric intangible plant is also consistent with the methodology SDG&E proposed in its general rate proceeding which is pending at the CPUC. Using consistent methodologies should avoid the potential for under or over collection of costs related to total electric intangible plant during the TO4 Formula. Moreover, this treatment is consistent with cost causation principles.

---

[1] *Northern States Power Co.*, Opinion 383, 64 FERC ¶61,324 a p. 63,379 (1993), *reh'g denied* 74 FERC ¶61,106 (1996) (emphasis in original).

Q10. How does SDG&E propose to modify Appendix VIII to address this issue?

A10. SDG&E proposes to modify Section 65 of Appendix VIII section I.B as follows:

> 65. Transmission Related Electric Miscellaneous Intangible Plant shall equal the total amount of Electric Miscellaneous Intangible Plant recorded in FERC Account No. 303 associated with transmission as a result of either (a) an allocation to transmission function based on the Transmission Wages and Salaries Allocation Factor or (b) directly assigned to the transmission function where: (i) direct assignment is consistent with cost causation principles, (ii) the relationship between cost incurrence and cost responsibility is obvious and reviewable and (iii) direct assignment is reasonable and cost allocation is unreasonable, *e.g.*, it would be unreasonable to use a labor ratio to allocate the balance to both distribution and transmission functions where the costs at issue have been affirmatively linked to the transmission function only.

Permitting this option here, just as we've done for electric A&G Expenses permits SDG&E to ensure that it follows cost causation principles and objective factors in determining whether and to what extent it should allocate A&G costs using a labor allocator or directly assign costs in specific types of situations where use of a labor ratio allocator would be unreasonable.

Q11. Does this conclude your testimony?

A11. Yes, it does.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Michelle Somerville, being duly sworn, on oath, says that she is the Michelle Somerville identified in the foregoing prepared direct testimony; that she prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of her knowledge and belief; and that if asked the questions appearing therein, her answers would, under oath, be the same.

Michelle Somerville
Michelle Somerville

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, Rosalinda Rossi, a Notary Public, personally appeared Michelle Somerville, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that she executed the same in her authorized capacity, and that by her signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ROSALINDA ROSSI
COMM. #1858772
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jul 24, 2013

Rosalinda Rossi

Exhibit No. SDG-6

UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF

RAULIN R. FARINAS

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY

EXHIBIT NO. SDG-6

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company	**)**	**Docket No. ER13-___-000**

PREPARED DIRECT TESTIMONY OF
RAULIN FARINAS
ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name and business address.

A1. My name is Raulin R. Farinas. My business address is 8315 Century Park Court – CP21C, San Diego, CA 92123-1548.

Q2. By whom are you employed and in what capacity?

A2. I am employed by San Diego Gas & Electric, (SDG&E) as a Principal Electric Analysis Advisor. In this capacity, I analyze and develop proposals for SDG&E in transmission rate proceedings before the Federal Energy Regulatory Commission (FERC or Commission) to determine base transmission revenue requirements for the transmission function.

Q3. Please briefly describe your educational background and identify any professional affiliations to which you belong.

A3. I received a Bachelor of Science in Business Administration, with an emphasis in Accounting, from Old Dominion University in 1985. I also received a Master of Business Administration degree from the University of San Diego in 1997.

I am a licensed Certified Public Accountant from the state of Kentucky, and I am an active member of the Kentucky Society of Certified Public Accountants. In addition, I am a Certified Management Accountant and a member of the Institute of Management Accountants.

Q4. Please describe your professional experience and employment history.

A4. I have been employed by SDG&E since 2002, first in the capacity of a Regulatory Economic Advisor, and from 2007 to the present in my current position as a Principal Electric Analysis Advisor. I was also employed by American Water Works Service Co. and California-American Water Co. from 1986 through 2002 in various roles including Revenue Requirement Specialist, Senior Accountant, Staff Accountant, and Rate Analyst.

I have also been employed by National University (2001 – Present) and Webster University (2010 – Present) on a part-time basis as a Certified Core Adjunct Faculty and as an Adjunct Associate Professor, respectively. In these roles, on occasion, I teach at the universities' School of Business Administration, graduate and undergraduate courses in financial accounting, managerial accounting, and basic finance.

1. Purpose and Summary

Q5. What is the purpose of your testimony?

A5. I will be discussing the following topics:

<u>Section I - Derivation of Forecast Period Capital Additions Revenue Requirements (FC).</u> This section explains the derivation of the of the Forecast Period revenues component of the total Base Transmission Revenue Requirements (BTRR).

<u>Section II – Derivation of True-Up Adjustment (True-Up or TU) for Retail and Wholesale Customers.</u> This section explains the derivation of the Retail and Wholesale True-Up Adjustment and discusses how the Retail True-Up Adjustment is converted to the Wholesale True-Up Adjustment. This section also discusses the application of the Retail True-Up Adjustment to both Retail and Wholesale Customers.

<u>Section III – Purpose and Derivation of Interest True-Up Adjustment.</u> This section discusses the need and derivation of the Interest True-Up Adjustment of SDG&E's BTRR.

<u>Section IV - Derivation of Incentive Revenues per Appendix VIII.</u> This section *explains how incentive revenues are calculated based on the Incentives requested for a* given incentive project.

<u>Section V - The Development of $BTRR_{ISO}$.</u> This section explains the derivation of the ISO BTRR.

Section VI – Derivation of the California Independent System Operator (CAISO) High Voltage/Low Voltage Separation Studies. This section explains how SDG&E develops High Voltage (HV) and Low Voltage (LV) separation studies for CAISO Transmission Access Charge purposes.

Section VII - The Derivation of Retail BTRR Rates and Wholesale TRR in cost Statement BL. This section describes the development of Retail BTRR Rates and the Wholesale TRR.

Section VIII - Changes to Appendix IX. This section deals with the changes made to Appendix IX.

I - Derivation of Forecast Period Capital Addition Revenues

A. The Need to Weight Transmission Project and General and Common Plant Costs to Determine Forecast Revenues

Q6. Please describe how you developed the transmission revenue requirements related to the forecast of transmission, general and common plant additions, referred to as Forecast Period Capital Additions Revenue Requirements in the BTRR formula.

A6. The Forecast Period Capital Additions Revenue Requirements (FPCARR) of the BTRR formula recovers the costs related to forecast plant additions reflected in the Forecast Period. For Cycle 1, the Forecast Period is the 27-month period from June 2012 through August 2014. Mr. Lucero explains why the Forecast Period in Cycle 2 and Cycle 3 will change slightly (Exhibit No. SDG-2).

Q7. Please explain the process you went through once you received the Forecast Plant additions from John Jenkins?

A7. For the Forecast Period, John Jenkins shows for every month, all individual transmission project, their costs, and in-service dates. To correctly calculate the revenues related to the Forecast Plant additions, the costs are weighted by number of months customers will benefit from the project within a given cycle. Exhibit No. SDG-6-1 illustrates this point.

Typically, any cycle filing will have a 12-month Rate Effective Period whose last month will coincide with the last month of the Forecast Period as shown on lines 7 and 11 of Exhibit No. SDG-6-1. If a transmission project goes into service in the first month of the Rate Effective Period, customers get the use of this project for 12 months during the Rate Effective Period. Thus, for this project it is given a weighting of 1, or 12 divided by 12 (12 months in service divided by 12 months that are in the Rate Effective Period). If a project goes into service in the second month of the Rate Effective Period it is used and useful by customers for 11 months during the Rate Effective Period, so this project cost is given a weighting of 11 divided by 12 (11 months in service divided by 12 months that is in the Rate Effective Period).

The above methodology is used to lower the applicable cost weightings for each succeeding month in the Forecast Period. Thus, under this method, any project in the Forecast Period that goes into service in any month prior to the start of the Rate Effective Period will automatically get a weighting of 1 or 12/12 as it is used and useful by the customer for the entire Rate Effective Period. Line 16 shows the monthly weighting percentages depending on the month the transmission project goes into service.

Line 18 shows the un-weighted costs of monthly hypothetical projects by in service months and line 21 shows the monthly weighted project costs, which were derived by taking the monthly weighting percentages, line 16, times the monthly un-weighted projects costs, line 18. Once the weighted costs are determined for each month they are summed and then adjusted by a small retirement factor to reflect possible retirements to the Forecast Plant additions.

B. Derivation of AFCR to Derive Revenues Related to Non-Incentive Forecast Plant Additions – Exhibit No. SDG-6-5 Page 4

Q8. Have you prepared an exhibit to explain how you develop the Annual Fixed Charge Rate (AFCR), as well other aspects of the TO4 Formula?

A8. Yes. I have prepared Exhibit No. SDG-6-5, using Statement BK-1 derived from Appendix VIII as an illustrative example. Statement BK-1 also shows how incentive equations will work for illustrative incentive projects, which I discuss below. Because SDG&E is not filing for any incentives at this time, the costs shown in Exhibit No. SDG-6-5 Statement BK-1 are only illustrative and do not tie to SDG&E's actual Statement BK-1. Lolit Tanedo in her testimony (Exhibit No. SDG-4) discusses the development of the actual Cycle 1 BTRR.

Q9. Once you have determined the total amount for weighted Forecast Plant additions, how do you then develop Forecast Period plant addition revenues?

A9. To develop Forecast Period plant addition revenues I multiply the sum of the weighted Forecast Period plant additions costs times an AFCR.

Q10. How did you develop the AFCR?

A10. I have used an AFCR that is calculated in the same fashion as SDG&E currently uses in its TO3 formula. That is, I take Base Period revenue shown in Exhibit No. SDG-6-5, Statement BK-1, page 4 line 3, make certain adjustments to exclude costs not applicable to forecast costs, and then divide this amount by total transmission gross plant in the Base Period as reflected on line 12. This amount is a thirteen month weighted average balance of gross transmission plant related to the Base Period.

Q11. In general, have you found in TO3 that the derivation of the AFCR produces reasonable results?

A11. Yes. The FERC staff proposed this method in SDG&E's TO2 and I have found that this method produces reasonable results. That is, the method captures a reasonable amount of revenues related to plant additions..

C. Derivation of Revenues Related to Forecast General and Common Plant Exhibit No. SDG-6-5 Page 4 Line 18

Q12. As part of your Forecast Plant additions, do you also forecast General and Common plant that SDG&E will incur during the Forecast Period?

A12. Yes. SDG&E includes in its Forecast Period General and Common plant additions it anticipates it will incur in the Forecast Period.

Q13. How do you develop this forecast and related forecast revenues?

A13. I basically use the same approach that I use for SDG&E's transmission plant addition forecast. That is, SDG&E individuals who are knowledgeable in electric General and Common Plant additions provide me the forecast of additions. I then take the Common plant additions and allocate them between the Electric and Gas Division using SDG&E's new Common Plant Labor Allocation factor as described in the testimony of Michelle Somerville.

Once the forecast Common plant is allocated to the Electric Division I add this to the forecast of electric general plant. I then multiply this sum times SDG&E's Transmission Wages and Salaries Allocation Factor, better known as the transmission labor ratio to determine what portion is assignable to transmission service. At this stage I then weight these monthly addition costs similar to how I weight transmission plant additions in the Forecast Period as explained in part A above.

Once the weighted electric and general plant additions amounts are determined, I add the sum of these weighted costs to the sum of the transmission plant addition weighted costs. The sums of these are shown in Exhibit No. SDG-6-5 page 4 line 16.

Q14. With regards to the derivation of the Forecast Electric and General and Common plant do you have a work paper that supports the above process you described?

A14. Yes. The work paper is included in Volume 5 of this filing under the tab labeled "Summary of Weighted HV-LV Forecast Plant Additions."

SECTION II – TRUE-UP ADJUSTMENT RETAIL AND WHOLESALE CUSTOMERS

A. Calculation of Retail TU Adjustment

Q15. Please explain the True-Up Adjustment component of SDG&E's transmission formula used to derive its Base Transmission Revenue Requirements.

A15. As discussed by Ed Lucero in his testimony (Exhibit No. SDG-2), the first True-Up Adjustment component of the TO4 transmission formula will be part of SDG&E's BTRR in TO4 Cycle 2. The True-Up Adjustment will work in the exact manner as it does in SDG&E's TO3 Formula.

Q16. How will the TO4 True-Up Adjustment be calculated?

A16. The Formula first calculates a True-Up Adjustment by taking the difference of the True-Up Period, monthly transmission revenues recorded during this period less transmission rate revenues calculated from a True-Up Period cost of service. The total True-Up Adjustment is then equal to the sum of the monthly differences between the recorded transmission revenues and the True-Up transmission rate revenues that are calculated from the True-Up Period cost of service. These differences are then adjusted on a monthly basis for interest to insure customers and shareholders are compensated for the time value of money related to these monthly differences. In essence, the True-Up Adjustment component of SDG&E's transmission formula makes it work somewhat like a balancing account. Exhibit SDG-6-2 illustrates the True-Up Adjustment calculation as I explained above. For illustrative purposes as shown in Exhibit SDG-6-2, line 33, the True-Up Adjustment amount that would be included in the derivation of the BTRR is an illustrative over-collection of $7,624,594.

Q17. In calculating the TU Adjustment, do you adjust recorded BTRR in some way?

A17. Yes. When SDG&E records its retail rate BTRR these revenues include all components of the BTRR including prior period TU Adjustment revenues and prior period Interest TU Adjustment revenues (I discuss this later below). To insure SDG&E uses the correct retail transmission recorded revenues in its TU Adjustment, it must first subtract from recorded revenues, prior period TU Adjustments revenues (assuming this was an under-collection in the prior period) and Interest TU Adjustments that were included in the derivation of the prior period BTRR.

Q18. What would be the problem if SDG&E did not exclude from the recorded retail BTRR revenues, prior period TU Adjustments and Interest TU Adjustments revenues?

A18. If SDG&E did not exclude from recorded retail BTRR revenues its TU Adjustment and Interest TU Adjustment, it would essentially result in a double "true-up" of these adjustments, which is incorrect.

Q19. To correctly calculate the TU Adjustment, how does SDG&E exclude the prior period's TU Adjustment and Interest TU Adjustment?

A19. As reflected in Exhibit No. SDG-6-2, pages 1-3, lines 7 and 13, for the months of September 2014 through December 2014, SDG&E excludes from recorded retail BTRR its TU Adjustment revenues by subtracting a monthly amortization of these amounts from recorded revenues. Work paper Exhibit No. SDG-6-2 shows the derivation of an annual amortization rate, and how this amortization is multiplied by the monthly recorded sales during the true-up period. There were no amounts shown on lines 10 and 16 to adjust for the Interest True-Up Adjustment, since there was no Interest True-Up Adjustment amount included in the BTRR for the Cycle 2 filing. The adjustment for the Interest True-Up will be reflected in TO4, cycle 4.

B. Derivation of CAISO Wholesale TU Adjustment

Q20. Under its existing TO3 transmission formula, does SDG&E calculate a separate True-Up Adjustment for its Retail and Wholesale customers to derive their respective Retail and Wholesale BTRR?

A20. Yes. In SDG&E's TO3 transmission rate formula there were two separate True-Up Adjustment calculations, one for Retail customers and another more complicated one for Wholesale. The True-Up Adjustment for Retail customers is derived as indicated above.

For Wholesale customers, the True-Up Adjustment is calculated separately similar to retail with the exception that ISO wholesale recorded revenues is calculated on a rather complicated procedure that takes the prior period wholesale cost of service and converts these to retail rates as if they were metered at transmission level. That is, the recorded transmission revenue for Wholesale customers is a proxy amount of wholesale revenues that would have been collected from retail customers at transmission level, instead of at the meter level.

Q21. What does it mean when you state that "for wholesale customers, the recorded transmission revenues reflect a proxy amount of wholesale revenues that would have been collected from retail customers at transmission level"?

A21. The recorded wholesale transmission revenue is a proxy amount because in actuality SDG&E does not directly bill CAISO wholesale customers as it does retail customers. In calculating its Wholesale True-Up Adjustment, SDG&E calculates a proxy recorded wholesale transmission revenue that would have been collected during the true-up period that is compared against wholesale transmission rates revenues.

Q22. To make the CAISO wholesale TU Adjustment less complicated, is SDG&E proposing a more simplified manner in which it will calculate its CAISO TU Adjustment in TO4?

A22. Yes. In TO4, SDG&E is proposing that a single TU Adjustment method be used to derive the True-Up Adjustment amount whose result will be applicable to both Retail and ISO wholesale customers. This in effect will greatly simplify the calculation of the ISO Wholesale TU Adjustment.

Q23. Using the Retail True-Up Adjustment amount calculated in Exhibit SDG-6-2, page 3, line 33, please indicate how this amount will be utilized in the derivation of the Wholesale BTRR?

A23. Since the Retail True-Up Adjustment will be applicable to both retail and wholesale customers, the Retail True-Up Adjustment amount of $7,624,594 shown in Exhibit SDG-6-2 will simply be carried forward to Exhibit SDG-6-7, line 14, page 1 of 2, to derive the wholesale BTRR.

SECTION III – PURPOSE AND DERIVATION OF THE INTEREST TRUE-UP ADJUSTMENT.

Q24. Does SDG&E propose to retain an Interest True-Up Adjustment provision to derive its BTRR under the TO4 Formula? If so, please explain this adjustment and how SDG&E will implement this proposal in the TO4 Formula.

A24. Yes. SDG&E will retain in its TO4 formula, the Interest True-Up Adjustment component in deriving its BTRR that is currently being used in its TO3 BTRR formula. For example, in TO4 Cycle 2, once a True-Up Adjustment balance is calculated, SDG&E will have a True-Up Adjustment balance at the end of December 31, 2013. This balance will be on SDG&E's books until September 1, 2014 when the Cycle 2 rates are billed. To the extent there is a interest cost for this balance between January 1, 2014 and September 1, 2014, the Interest True-Up Adjustment will accumulate the interest cost during this period so that is can be credited or charged to customers as the case may be. Thus, if the True-Up Adjustment is an over-collection, then customers need to be compensated for the carrying charge on the over-collection to make them whole. Similarly, shareholders need to be compensated for any under-collection in the True-Up Adjustment to make them whole as well.

Q25. Please explain the derivation of the Interest True-Up Adjustment component of the TO4 BTRR and its purpose.

A25. Exhibit SDG-6-2, lines 26 through 31, shows the interest expense calculation, following FERC convention, where interest is compounded on a quarterly basis.

Exhibit No. SDG-6-3 illustrates the derivation of the Interest True-Up Adjustment. This exhibit demonstrates, with hypothetical numbers, how the TO4 Cycle 3 Interest True-Up Adjustment is calculated on a monthly basis and then summed in the aggregate to come up with a total Interest True-Up Adjustment amount of $1,013,798, the amount that I am proposing to reflect as the Interest True-Up Adjustment.

Q26. Please continue explaining the derivation of the Interest True-Up Adjustment.

A26. The derivation of the Interest True-Up Adjustment is relatively straightforward. SDG&E would begin the calculation by bringing forward the True-Up Adjustment balance that was calculated in the prior cycle filing. In this example, since we are calculating the Interest True-Up Adjustment of the TO4 Cycle 3 True-Up Adjustment, we would bring forward the prior Cycle 2 True-Up Adjustment balance as of 12/31/2013, equal to an under collection of $32.1 million, for illustrative purposes. In TO4 Cycle 2, I would have shown this under-collected balance in the December 31, 2013, or the last month of the True-Up Adjustment calculation.

To derive the Interest True-Up Adjustment, in the TO4 Cycle 3 filing, I will show this under collected $32.1 million balance as the beginning balance in the True-Up Adjustment calculation. Thus, this amount is shown in the January 2014 column on line 1, in the January 2014 column, as shown in Exhibit SDG-6-3 line 1. Interest is accrued on the beginning balance until the amount is fully amortized at the end of the rate effective period. The Interest True-Up Adjustment that is included in the BTRR is the amount of interest accrued from the beginning of true-up period until the end of the true-up period. The hypothetical TO4-Cycle 3 Interest True-Up Adjustment amount equal to approximately $1.014 million is shown on line 18 in the total column.

Q27. Why does the Interest True-Up Adjustment reflect a more accurate True-Up calculation?

A27. In the illustration, absent the Interest True-Up Adjustment, shareholders would not receive the interest owed them on the $32.1 million under collection. This is because when I calculated the $32.1 million under collection as of December 31, 2013 in TO4 Cycle 2, SDG&E did not begin collecting this amount from customers until nine months later, or until the Cycle 2 rates went into effect on September 1, 2014. Therefore, for eight months, from January 2014 through August 2014, shareholders will lose the interest, or time value of money, on the $32.1 million under collection.

By including the $32.1 million balance in the first month, January 2014, of the following Cycle 3 Interest True-Up Adjustment calculation as shown on line 1 of Exhibit No. SDG-6-3, shareholders will be compensated for the interest owed them so that they remain whole.

SECTION IV - DERIVATION OF INCENTIVE REVENUES PER APPENDIX VIII

Q28. Has SDG&E included in Appendix VIII language to reflect the recovery of incentive revenues for certain transmission projects for which it will seek certain incentives under Order 679?

A28. Yes. In its TO4 Formula SDG&E has included language to accommodate the recovery of the following incentives

- Incentive ROE adder to a transmission project that is in the Forecast Period

- Incentive ROE adder to a transmission project that is in the Base Period
- Rate of Return on CWIP that is in the Forecast Period
- Rate of Return on CWIP that is in the Base Period
- Recovery of 100% of abandoned plant

Q29. How will SDG&E seek recovery of the above incentives pursuant to its TO4 formula?

A29. SDG&E will file for incentive treatment consistent with the procedures laid out in Order No. 679. Approved incentives will be flowed through the TO4 Formula as described below.

Q30. Does SDG&E plan to make changes to its recordkeeping as a result of having both Non-Incentive and Incentive plant in service pursuant to its TO4 formula?

A30. Yes. SDG&E will put a mechanism in place to track separately the activities associated with each of its incentive plant is service projects. This will entail having separate sub-accounts for plant in service, depreciation expense, accumulated depreciation reserve, and other accounts necessary to track the applicable costs of each respective incentive project. The details still have to be worked.

A. Illustrative Examples of Cost Statements to Develop Incentive Revenues in Statement BK-1

Q31. Have you prepared illustrative examples of applicable cost statements to explain how you intend to incorporate the incentive costs into these statements?

A31. Yes. I have prepared Exhibit No. SDG-6-4 that shows examples of Statement AD, AE, AF, AJ, and AV that would be adjusted by including incentive transmission projects in the base period. I have used the term Incentive Transmission Plant where applicable and Non-Incentive Transmission Plant to reflect existing transmission plant.

Q32. What modification did you make to Statement AV (cost of capital) to reflect those incentive projects for which SDG&E is authorized to receive an incentive ROE?

A32. Statement AV was modified to incorporate a Statement AV to derive a cost of capital grossed up for income taxes for Non- Incentive projects and a Statement AV to derive a cost of capital grossed up for income taxes including an incentive ROE adder applicable to the incentive project. For example, Statement AV in Exhibit SDG-6-4, page 5 of 7, beginning on line 32 develops two costs of capital rates. One rate is applicable to Non-Incentive rate base (lines 32 through 43) and the other rate is applicable to Incentive rate base (lines 45 through 56) for a specific incentive project. Non-Incentive cost of capital uses an ROE equal to 11.3%. For illustrative purposes I have used a 100 basis point adder for an ROE incentive adder for a specific project. For instance, as shown on line 45, the ROE for this project that qualifies as incentive will be 12.30%. In the same exhibit, page 7 of 7, lines 1 through 33, shows the derivation of the incentive cost of capital rate.

Q33. Based upon the above modifications, Statements AD, AE, AF, AJ and AV appear to be the only cost statements that you have modified to reflect incentive project costs related to rate base and depreciation expenses. Is that correct?

A33. Yes. I have not modified or defined operation and maintenance (O&M) expenses related to incentive projects as it would be very difficult to determine the incremental O&M expenses related with each specific incentive project.

B. Illustrative Example of the Statement BK-1 Cost of Service to Incorporate Incentives.

Q34. Have you prepared an illustrative example of Statement BK-1, cost of service, to explain how you have incorporated the incentive costs into the cost of service?

A34. Yes. I have prepared Exhibit No. SDG-6-5, which provides an illustrative example of the Statement BK1, cost of service, to show how SDG&E proposes to incorporate these incentive costs into future formula filings. In explaining this exhibit I shall refer only to those cost statements of the Base Period and Forecast Period affected by the incentive modifications. All other components of the formula remain the same as discussed by Ms. Lolit Tanedo, in her testimony in Exhibit No. SDG-3, when she describes the development of the TO4 Cycle 1 revenues, which are derived in Volume 4.

Exhibit No. SDG-6-5, pages 1-3, show the revisions necessary to incorporate incentive project costs to derive the Base Period cost of service. Pages 4 and 5 show the modifications needed to derive Forecast Period revenues. Page 6 of Statement BK-1 summarizes the various revenue components that make up the total formula revenues for the cycle filings.

Q35. Please explain the proposed modifications to the recorded costs in the Base Period that shows Non Incentive and Incentive plant separately.

A35. Page 3 of Exhibit No. SDG-6-5 shows the derivation of transmission net plant. Section A of the page shows revenues related with non-incentive plant and Section B of the page shows incentive plant in service, lines 23 and 24. As indicated earlier, in future cycle filings, these amounts will come from Statements AD and AE. Page 2 shows the derivation of rate base. Similar to page 3, which shows net plant, Section A of page 2 shows the derivation of non-incentive rate base, and Section B shows the derivation of incentive rate base. On line 29, incentive net plant is brought forward from page 3.

Q36. Please explain how you developed in Section B, the plant balance amounts reflected in the incentive rate base, shown on page 2.

A36. These amounts come from the page 3 that develops net plant. For incentive projects that are in service, SDG&E would show a 13 month average for incentive projects that come from Statement AD and AE respectively.

Q37. Please explain the incentive costs shown on page 2, line 36.

A37. Line 36 on page 2 show the accumulated deferred income tax liability related to incentive projects that are booked as plant in service.

Q38. Explain the incentive cost components that appear in Section B, page 1 of the summary of cost of service of Exhibit No. SDG-6-5.

A38. Section B of page 1 develops the incentive revenue requirements related to the incentive projects. It is important to note that the property tax and any incremental O&M related to these incentive projects are shown in Section A as part of non-incentive revenue. The reason we have set up the revenue requirements in this manner is for ease of understanding, and because it would be virtually impossible to calculate the incremental transmission O&M and Administrative and General (A&G) expenses for each individual incentive project.

In addition, the costs listed in Section B of page 1 reflect only the return on rate base costs and depreciation expense related to the incentive projects. As described above, line 38 reflects the economic book depreciations expense. Line 41 represents the incentive, cost of capital grossed up for income taxes. This figure, which would come from Statement AV for future filings, reflects a base ROE equal to 10.8%, plus a 50 basis point CAISO adder, plus an incentive adder of 100 basis points. To summarize, page 1, line 48 shows the sum of Non-Incentive and Incentive revenues for the Base Period.

Q39. In deriving the Non-Incentive and Incentive Cost of Capital Rates for the Base Period, what specific date do you use to develop the capital structure upon which the cost of capital rate is derived?

A39. Consistent with the current TO3 formula, SDG&E proposes to continue to use a capital structure to derive its Base Period cost of capital that reflects the actual capital structure shown on SDG&E's books at the end of the last month of the Base Period.

C. Adjustments to Statement BK-1 to capture Forecast Period Incentive Modifications

Q40. Please explain how you derived incentive revenues for incentive projects shown in the Forecast Period as indicated on page 5 of 6 of Exhibit No. SDG-6-5. The derivation of the incentive revenues for the Forecast Period is based in part upon the annual fix charge rate (AFCR) methodology currently used in the TO3 formula to develop revenues for non-incentive projects that appear in the Forecast Period. This methodology is reflected in Appendix VIII and is consistent with the FERC Staff's recommendation to derive this revenue in the TO3 annual filings. I will briefly explain this methodology which is shown on page 4.

A40. Page 4, section A, indicates that the AFCR shown on line 14 is derived by taking total non-incentive Base Period revenues less those cost items shown on lines 4 through 9. SDG&E subtracts these cost items because they are related only to historical costs and not to future costs. The resulting revenue shown on line 10 is then divided by total non-incentive gross plant as shown on line 12 to yield the AFCR shown on line 14. This AFCR is then multiplied by the weighted non-incentive transmission project costs applicable to the Forecast Period shown on line 16 to produce forecast non-incentive revenues applicable to the Forecast Period, line 18.

Q41. In the discussion above, you used the term, "weighted transmission project costs" applicable to incentive projects. Please explain this term.

A41. In Section 1 above, I have explained this term applicable to non incentive projects. For incentive projects, the weighting of these projects will be the same as for how non-incentive projects are weighted.

D. Illustrative Calculation of the AFCR to Derive Revenues Resulting from a ROE Incentive Adder for a Transmission Project in the Forecast Period.

Q42. Please explain your criteria for selecting a method to calculate the AFCR to recover incentive costs for applicable projects.

A42. I have used two (2) criteria to calculate the AFCRs related to an incentive project.

- First, I wanted to use, if possible, an AFCR methodology currently used in the formula because the current methodology is familiar to interested parties and will facilitate their overall review and yields reasonable results. More particularly, this method has provided reasonable results in SDG&E's TO3 Formula annual filings.
- Second, an appropriate AFCR method should yield the least amount of a True-Up Adjustment in the following cycle to avoid significant cost over-recovery or under-recovery. The current TO3 AFCR method which I am proposing to apply, with some minor changes to incentive projects in the Forecast Period, should produce reasonable results, including a small True-Up adjustment in the following cycle.

Q43. Please explain how you calculated the AFCR applicable to incentive project(s) that reflect only a separate ROE incentive.

A43. For illustrative purposes, page 5 of Exhibit No. SDG-6-5 shows the AFCR calculation. Section A reflects the derivation of the AFCR for which "only" an incentive ROE has been authorized for projects. This section, in reality, is a mirror image of the existing AFCR method shown in Section A on page 4, with one minor exception. The Base Period revenues shown on line 3, page 5, were derived by recalculating Base Period revenues, located in Section A of page 1 of Statement BK-1, as if "all" non-incentive plant were to receive an incentive ROE. As indicated on page 5 line 3, this revenue is equal to $316.574 million. Exhibit No. SDG-6-6, page 1, reflects this statement BK-1 scenario.

For illustrative purposes, as indicated on this page, line 35 shows total Base Period Revenues (PYRR) equal to $316.574 million. This revenue reflects a non-incentive rate base equal to $1,220.553 million, shown on line 24. The one other change to this Statement BK-1 scenario appears on line 22 where I changed the Non-Incentive Cost of Capital rate to an Incentive Cost of Capital rate equal to 12.7129%. This Incentive Cost of Capital rate reflects a Statement AV cost of capital that is based on a

12.30% ROE. This would include the Base ROE equal to 10.80%, an ISO adder of 50 basis points and a ROE incentive adder of 100 basis points. The derivation of the 12.7129% Incentive Cost of Capital rate is shown on page 3 of Exhibit No. SDG-6-6 (Statement AV scenario) shown on line 33. Page 32 of Statement AV of this exhibit shows the other input used to derive the 12.7129% ICOC.

Q44. Once you calculate the $316.574 million discussed above, how do you finish calculating the AFCR shown in Exhibit No. SDG-6-5?

A44. As shown on page 5 in Section A, I reduce this amount by lines 4 through 8 and then take line 9 divided by total Base Period gross plant shown on line 11. This result then yields the $AFCR_{EU\text{-}IR\text{-}ROE}$ equal to 16.5503%. This percent is then multiplied times the Incentive Weighted Forecast Plant Addition of $100 million (for illustration only) on line 15, which represents the project additions for which SDG&E is requesting *"only"* an ROE incentive. Line 17 yields the incentive capital additional revenue.

E. Illustrative Calculation of AFCR to Derive Incentive Revenues for CWIP

Q45. How would SDG&E derive incentive revenues for a project for which it is seeking a return on CWIP?

A45. This method is shown in Exhibit No. SDG-6-5 Section B of page 5. Instead of using the AFCR methodology described above, SDG&E in Section B will simply multiply the 13 month weighted average incremental CWIP balances in the Rate Effective Period, as shown on line 20, times the Cost of Capital Rate shown on line 22 equal to 11.8691%. This amount includes a base ROE equal to 10.80%, plus the 50 basis points ROE adder.

Q46. Are the above proposed incentive revenue derivation methods for a project that gets a ROE adder or CWIP in the Forecast Period reasonable?

A46. Yes. In addition to the reasons discussed above in section (i), there are two other reasons why the above methodologies are reasonable.

- First, for a project that get an ROE adder, the proposed method collects slightly less than the first year revenues of a project in the Forecast Period. It is axiomatic that a project's revenue decreases over time as net plant is reduced. If SDG&E were to calculate the first year revenue requirement of a transmission project it would equal an amount in the range of 18% to 19% if one included O&M, depreciation, property taxes, income taxes, and cost of capital. However, the AFCR used for non-incentive plant, which is based upon total Base Period revenue (revenues determined on average net plant) to gross plant, serves as a reasonable proxy for the revenues for non-incentive forecast plant additions. Therefore, if for example there is a slight under recovery of incentive revenues related to the forecast plant addition in a Cycle 2 filing, the following cycle True-Up Period will compensate for this shortage.

- Second, even if the revenues derived for the forecast plan additions are slightly less than they would otherwise be, the Formula will always reconcile these revenues in the True-Up Period, which reflects actual recorded costs. This is also true for the CWIP project in the Forecast Period I discuss above

SECTION V - THE DEVELOPMENT OF $BTRR_{ISO}$

Q47. Please explain how SDG&E derives its Wholesale BTRR in Statement BK-2, Exhibit No. SDG-6-7, under its proposed TO4 Formula.

A47. Lolit Tanedo in her testimony goes into great detail as to how Cost Statement BK-1 is derived pursuant to language set out in Appendix VIII. In this section of my testimony I explain how I use the information in Statement BK-1 to derive CAISO BTRR in Statement BK-2. I have included Exhibit No. SDG-6-7 to illustrate how SDG&E derives its CAISO Wholesale BTRR in Statement BK-2. Since many of the cost components included in the derivation of the Retail Statement BK-1 BTRR are similar to those used in deriving its Wholesale BTRR, I start by taking the Total Prior Year Revenue Requirements from Statement BK-1 as shown in Section (A), line 1. From this amount, I make adjustments for those costs that are include in line 1, but are not applicable to Wholesale customers, namely (1) CPUC Intervener Compensation Expense, (2) South Georgia Income Tax Adjustment, and (3) Transmission Related Amortization of Excess Deferred Income Taxes Liabilities to derive the Wholesale Prior Year Revenue Requirements before FF&U as shown on line 12. To this amount, I add the True-Up Adjustment and Interest True-Up Adjustment shown on lines 14 and 16, respectively, to derive the Wholesale BTRR before Forecast Revenue Requirements.

Q48. Are there any other components needed to derive total Wholesale BTRR besides those described in the previous question?

A48. Yes. In addition to those items described previously, I also add (1) the Forecast Period Capital Additions Revenue Requirements, (2) Forecast Revenue Requirements for

Transmission Plant Held for Future Use, (3) Forecast Period Incentive Capital Additions Revenues, and (4) Transmission CWIP Incentive Projects Revenue Requirements, if any. Once these amounts are included, the Total Wholesale BTRR Excluding FF&U is derived, as illustrated on line 28. To be clear, however, SDG&E is not filing for any incentive projects in this Cycle 1 Filing.

Q49. When does the FF&U get included in the derivation of the total Wholesale BTRR?

A49. First of all, SDG&E does not include a provision for uncollectible expenses from bad debts in deriving its wholesale BTRR. The premise is that wholesale customers are a going concern and will remain solvent to pay for their obligations. Therefore, the only other cost to include in deriving its total wholesale BTRR is franchise fees, and is shown on page 2 of 2, lines 28 and 32. The total wholesale BTRR including franchise fees is shown on line 35, on page 2 of 2.

Q50. Why did you adjust the $BTRR_{ISO}$ to collect franchise fees?

A50. Similar to SDG&E's current formula practice under TO3, wholesale customers should be obligated to pay a base franchise fee because SDG&E is assessed this fee by political subdivisions within its service area in exchange for the privilege of locating transmission facilities on city and country roads located throughout its service territory. To calculate the $BTRR_{ISO}$ associated with these fees, I use the same franchise fee percentages I employed in the calculation of the BTRR applicable to End Use Customers: A base franchise fee percentage factor, which currently is 1.0275%.

Q51. In deriving SDG&E's retail BTRR, why did you include the South Georgia income tax adjustment?

A51. Prior to restructuring, the CPUC regulated SDG&E's bundled retail rates. Prior to the Economic Recovery Tax Act of 1981, SDG&E, under CPUC ratemaking, flowed through to customers the tax benefit due to tax depreciation being greater than book depreciation. This accounting method differs from FERC ratemaking accounting, which requires full normalization of taxes to ratepayers. In cases where investor owned utilities have flowed through these benefits to customers, FERC requires that to the extent that past retail ratepayers have received greater tax benefits due to flow through accounting, SDG&E must make an adjustment that increases income taxes to current retail customers to recapture past flow-through benefits that retail customers received in the past which now must be normalized. This adjustment is called the South Georgia Adjustment to income taxes. As a result of this adjustment, retail income taxes, and thus retail BTRRs are slightly higher than if SDG&E had used fully normalized income taxes since it started to book its transmission costs.

Q52. In deriving CAISO BTRR, why did you exclude the South Georgia income tax adjustment as shown on line 6 of page 1 of 2, Exhibit No. SDG-6-7?

A52. The exclusion basically reflects that CAISO customers are charged on a fully normalized tax basis as required by the Commission.

SECTION VI.   CAISO HV AND LV SEPARATION STUDIES FOR TO4 CYCLE 1

Q53. Please explain how Statement BK-2 CAISO BTRR is split into HV and LV revenue components and how this information flows to Statement CAISO BL.

A53. I use HV and LV gross plant factors, which are explained below and shown in the last few pages of Statement BK-2 to derive this revenue splits and then this information flows to the Statement CAISO BL which takes the HV and LV BTRR splits and adds this to the Transmission Revenue Balancing Account Adjustment (TRBAA) HV and LV splits, which I discuss below to derive HV and LV Transmission Revenue Requirements that is needed by the CAISO to derive its annual CAISO Transmission Access Charge (TAC).

Q54. Has SDG&E used the most current CAISO guidelines to derive the CAISO HV and LV components for TAC Purposes?

A54. Yes. SDG&E, in the instant filing, has followed the CAISO's guidelines as indicated in the CAISO Tariff to separate all elements of its transmission facilities into HV and LV components. Similarly, the TRBAA cost components are separated into HV and LV components as discussed below, and follow CAISO Tariff guidelines

Q55. Is there a Cost Statement in the instant filing for TO4 Cycle 1 that explains how the CAISO HV and LV revenue components are derived?

A55. Yes. Cost Statement BK-2 in volume 4, illustrates how the CAISO HV/LV components are derived.

Q56. Using this cost statement, please explain how you separated the CAISO BTRR into the CAISO required TAC voltage components?

A56. Based upon the CAISO's guidelines to separate HV and LV facilities mentioned above, SDG&E developed the following studies to show the voltage separations.

- For TO4 Cycle 1, the HV and LV splits are based upon the HV and LV gross plant balances on SDG&E's books as of May 31 of the Base Period. For the Base Period, this is shown in Section B, Part 1, lines 14 through 17. The work paper that supports this split is in Volume 5. A similar work paper will be included in subsequent TO4 cycle filings.
- With the exception of Cycle 1, all other HV and LV splits will be based up HV and LV gross plant balances on December 31, which is the last month of the Base Period for subsequent cycles.
- New HV and LV Facilities for the Cycle 1 Forecast Period – This voltage classification is based upon SDG&E's transmission facilities that were shown to be going into service for the Forecast Period, which covers the period from June 1, 2012 through August 31, 2014. The HV and LV split for the forecast period is shown in Section B, Part 2, lines 20 through 22. Additional work papers showing this separation study are shown in Volume 5, and the derivation of these splits is explained in the testimony of John Jenkins.

Q57. How did you use the above information to develop the CAISO TAC voltage components?

A57. As shown in Exhibit SDG-6-7, page 2 of 2, Section A, I list the various revenue components that make up the total ISO BTRR. The Wholesale BTRR from prior year is shown on line 1. This number reflects revenues associated with Existing Facilities through May 2012. To separate this revenue into HV and LV facilities, I allocate the $340.796 million between HV and LV components based upon the transmission facility gross plant balances as of May 2012. These balances come from the respective HV/LV studies as described in the preceding question and answer. The segregation of the existing BTRR between HV and LV facilities is shown on line 18.

The Wholesale BTRR from forecast plant additions is the sum of lines 3, 5, 7, and 9, as shown on line 23, of Section B, Part 2. This amount is then segregated between HV and LV facilities using the ratios developed on line 22, of Section B, Part 2.

On page 2 of 2, in Section C, I summarize the final Wholesale BTRR by including applicable franchise fees.

In the last step, I then combine these amounts with SDG&E's HV and LV

TRBAA components, and the HV and LV Standby Revenues, to develop the HV and LV TRR, which are given to the CAISO for its TAC calculations.

Q58. Will SDG&E use the above process in future annual formula filings under TO4 to separate its HV and LV revenue components?

A58. Yes. When SDG&E files its annual formula filings, it will update each HV-LV separation study as indicated above so that the revenues will be classified based upon the most current gross plant balances.

Q59. How does the CAISO use the HV/LV revenue splits that are given to it by SDG&E?

A59. As required by the TAC, each Participating Transmission Owner (PTO) provides the CAISO with the transmission revenues for each component. The CAISO then takes the HV component for each PTO and combines these amounts through an allocation process to calculate the cost shifts amongst the PTOs.

Q60. How does SDG&E recover the CAISO monthly TAC charges from its retail customers?

A60. SDG&E recovers this amount through its Transmission Access Charge Balancing Account Adjustment (TACBAA) charge. The TACBA is filed with the FERC every December and is a rate applicable to retail transmission service for the following year. The TACBA charge is in addition to the total retail transmission revenues per the formula, as shown on page 6, line 36 in Statement BK-1.

Q61. Based upon the CAISO HV-LV revenue components shown in Exhibit SDG6-7, did you prepare an exhibit where you combined the revenue components from Exhibit SDG6-7 with the wholesale TRBAA that are sent to the CAISO for the development of the CAISO TAC and wheeling rates?

A61. Yes. For illustrative purposes in Exhibit SDG6-8, I took the ISO HV and LV base transmission revenue requirement components shown on line 1 of this exhibit and combined them with the existing wholesale TRBAA components. On line 9 of this exhibit, I also show the updated gross load for SDG&E. This gross load reflects retail load adjusted for the forecast period adjusted to transmission level. I also use this cost statement to prepare Appendix I, which is attached to the cover letter of this filing. Lastly, I want to point out that I am sponsoring Appendix I.

Q62. Please explain how you derived SDG&E's new HV and new LV Wheeling Access Charge.

A62. On page 1 in Statement BL, section CAISO Wholesale TRBAA & HV-LV Utility Specific Rate, I show the derivation of SDG&E's LV Wheeling Charge. The LV Wheeling Access Charge is billed by the CAISO to any Scheduling Coordinator that wheels through SDG&E's LV transmission grid. In Statement BL, I show a LV Access Charge, which is equal to the LV Wheeling Access Charge. SDG&E is authorized to bill the LV Access Charge to any municipal entity that obtains low voltage transmission service under SDG&E's TO Tariff.

Q63. Given SDG&E's new ISO transmission revenue requirements, is it necessary to develop new TRBAA allocation amounts that you must forward to the ISO as a result of SDG&E's formula transmission filing?

A63. No. The wholesale TRBAA amount and its allocation between HV and LV are developed once a year in SDG&E's annual TRBAA filing. In this filing, SDG&E will use the HV-LV wholesale TRBAA-TACBAA rates for 2013 that the Commission approved on February 4, 2013 in Docket No. ER13-602.

SECTION VII – THE DEVELOPMENT OF RETAIL BTRR RATES AND WHOLESALE BTRR IN COST STATEMENT BL

Q64. Please explain how you derived and allocated $BTRR_{EU}$ to Retail Customer Classes.

A64. To derive retail customer class revenue requirements, I allocated total retail BTRR shown in Statement BK-1 using FERC's standard 12 coincident peak (CP) allocation method.

Q65. Please describe how you developed the 12 CP allocator.

A65. First, I defined the retail customer classes to which I needed to allocate transmission costs. These customer classes include the following:

- Residential
- Small Commercial – this class includes those commercial customers that are billed only on an energy basis.
- Medium & Large Commercial – this class includes those larger commercial and industrial customers that are currently billed transmission and distribution costs both on a demand and energy basis.
- Street Lighting
- Standby Customers

Once I defined these classes, I then used load research information to develop class-specific demand at the time of SDG&E's monthly system peak up to the transmission level, *i.e.*, adjusted for distribution losses. The load information upon which I developed the retail 12-CP data is included in Statement BB-WP Page 1, contained in Volume 5.

Q66. What time interval did you use to develop this load research information?

A66. I have used a five-year average of load information for this purpose. In my work paper Statement BB-WP Page 1, I show the historical 12 CP data for each customer class for each year of the five year period. This data is shown at the customer meter level. Once I had developed the 5-year average. I then adjusted the 12 CP data by adding distribution losses to reflect this data at the transmission level. Statement BB shows the development of the 12 CP allocator. In future annual filings, SDG&E will simply subtract the oldest year data and add the most current year's data to the 5-year's worth of load research data to develop the following year's 12 CP allocators.

Q67. Once you developed the 12 CP allocator, how did you derive retail customer class transmission revenue requirements?

A67. At page 3 of Statement BL, I took the loss adjusted 12 CP data and used these class demands to allocate transmission revenue requirements from Statement BK-1 to each customer class.

Q68. Please explain how you then developed retail transmission rate design.

A68. SDG&E's TO3 Formula simplified SDG&E's retail rate design by creating one transmission rate applicable to each End Use Customer class. In its TO4 filing, SDG&E is proposing to maintain the same retail rate design that was in effect for its TO3 Formula. To better explain this concept, I will provide some background on SDG&E's historical retail rate treatment. In the past, SDG&E maintained the following rate schedules:

- **Residential**
  DR, DR-LI, DM, DS, DT, DT-RV, DR-TOU, DR-SES, EV-TOU, and EV-TOU-2.
- **Small Commercial**
  A, A-TC, A-TOU, and PA
- **Medium & Large Commercial & Industrial**

AD, AY-TOU, AL-TOU, DG-R, A6-TOU, and OL-TOU.

- **<u>Street Lighting</u>**

  DWL, OL-1, OL-2, LS-1, LS-2, and LS-3

- **<u>Stand-by Service</u>**

  S and S-I

The numerous schedules within each customer class are a function of CPUC rulings dealing mostly with distribution cost of service ratemaking issues. Because these distribution rate design designations do not have to be reflected in transmission rate design, SDG&E developed one transmission rate applicable to each End Use Customer class under its TO3 Formula, which will continue in its TO4 Formula.

Q69. Where do you show the design of these rates?

A69. At pages 4 through 14 in Statement BL, I show the rate design applicable to each rate. On page 1, I show a summary of the proposed transmission rates for the Rate Effective Period beginning in September 1, 2013. Page 4 demonstrates that the residential transmission revenue requirements were simply divided by total residential kWh at the meter to derive a single $/kWh rate for this class. The same procedure was used for the Small Commercial class, which contains customers that are metered only on an energy basis. For the Medium & Large Commercial class, I designed rates to recover costs on a monthly maximum non-coincident demand (100%), monthly maximum non-coincident demand (90%), Summer and Winter Maximum On-Peak Period Demand, Summer and Winter Maximum Demand at Time of System Peak. That is, I added the maximum monthly non-coincident billing peak demands for each customer to arrive at the monthly billing determinants for this class.

Q70. In deriving the Medium & Large Commercial class transmission rates, did you recognize the fact that these customers are served at different voltage levels?

A70. Yes. Recognizing that some of these customers are served at secondary, some at primary and some at transmission voltage levels, I derived three voltage-differentiated transmission rates for this class. Pages 6 through 12 of Statement BL show the derivation of these three rates for this customer class.

Q71. Mr. Farinas, was the rate design referenced above prepared in accordance with Appendix IX of SDG&E's transmission owner tariff?

A71. Yes it was. Appendix IX of SDG&E's current TO Tariff provides the guidelines for determining SDG&E's end use customer class transmission charges, low voltage access charge, high voltage utility-specific rate and the allocation of base transmission revenue requirements applicable to high voltage and low voltage transmission facilities.

Q72. Based upon the rates you have developed, have you calculated monthly revenues by rate class under the current rate design?

A72. Yes. On Statement BH, I have derived monthly transmission revenues by rate class under rates currently in effect for the first 12-months of the Rate Effective Period ending August 31, 2014.

Q73. Have you developed monthly transmission revenues by rate class under proposed rates for the Rate Effective Period?

A73. Yes. This is shown in Statement BG.

Q74. Did you develop a comparison showing how the total retail bills under the proposed rates will compare to the retail bill under rates currently in effect?

A74. Yes. This comparison, which is shown in Statement BG, page 9, shows that the customer's total bill will increase by approximately 1.5% as a result of the rates filed in this proceeding. In my view, this comparison provides a better understanding of the overall impact of the filing than does a comparison of current and proposed transmission rates viewed in isolation.

Section VIII – CHANGES TO APPENDIX IX

Q75. Please describe the Appendix IX section of SDG&E's transmission owner tariff.

A75. Appendix IX of SDG&E transmission owner describes the method by which SDG&E:

- Allocates Base Transmission Revenue Requirements (as determined in Appendix VIII) to End Use Customer classes, and designs transmission rates applicable to such End Use Customer classes assessed by SDG&E pursuant to its TO Tariff;
- Allocates Base Transmission Revenue Requirements (as determined in Appendix VIII) applicable to High Voltage Transmission Facilities and Low Voltage Transmission Facilities for purposes of designing voltage-differentiated Wheeling Access Charges assessed by the CAISO pursuant to its Tariff;
- Calculates the applicable Low Voltage Access Charge to be assessed pursuant to SDG&E's TO Tariff; and

- Calculates a High Voltage Utility-Specific Rate.

Q76. Please identify or describe the modifications that you are proposing to the Appendix IX section of SDG&E's TO Tariff.

A76. The redlined and clean versions of SDG&E's Appendix IX are included in this filing to highlight the changes that were made to the TO Tariff. Specifically, Pages 4-5, Section C has been modified to eliminate terminologies referencing Existing High Voltage and Low Voltage Facilities and New High Voltage Facilities and Low Voltage Facilities. These terms are no longer applicable to the CAISO TAC.

SECTION IX – OTHER ITEMS

Q77. Mr. Farinas, are there any other cost statements that you are sponsoring in this filing?

A77. Yes. I am also sponsoring the following cost statements: 1) BB; 2) BD; 3) BG; 4) BH; 5) BK1; 6) BK2; and 6) BL.

Q78. Does this conclude your testimony?

A78. Yes it does.

Exhibit - SDG-6-1

Illustrative Example of the Application of Weighting Factors

Exhibit No. SDG-6-1
Page 1 of 1

SDG&E

TO4 New Cycle 1 Filing Schedule

Line No.																																								Line No.
1																																								1
2																																								2
3	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	3
4				2011										2012													2013								2014					4
5																																								5
6																																								6
7																												**Rate Effective Period**												7
8																																								8
9	**Base Period**																																							9
10																																								10
11														**Forecast Period = 27 months to the end of the rate effective period**																										11
12																																								12
13																																								13
14																																								14
15	**B. Plant weighting to reflect months in service**																											12/12	11/12	10/12	9/12	8/12	7/12	6/12	5/12	4/12	3/12	2/12	1/12	15
16	Weighting applied to monthly plant add =														1	1	1	1	1	1	1	1	1	1	1	1	1	1	0.92	0.83	0.75	0.67	0.58	0.50	0.42	0.33	0.25	0.17	0.08	16
17																																								17
18	Unweighted monthly plant additions =														0	0	0	0	0	0	0	0	0	400	800	500	300	200	1200	6000	1000	6000	3000	8000	5000	3000	2000	1000	3000	18
19																																								19
20	Weighted Plant Adds (reflects No. of months																																							20
21	project is in service or in rate base (L16 x L18) =														0	0	0	0	0	0	0	0	0	400	800	500	300	200	1100	5000	750	4000	1750	4000	2083	1000	500	167	250	21
22																																								22

Exhibit - SDG-6-2

Illustration – Retail True-Up Adjustment Calculation

Exhibit SDG-6-2
San Diego Gas Electric Co.
Illustration of RETAIL True-Up Adjustment Calculation

Line No.	TO4-Formula Cycle in Effect / Description	Cycle - 1 Jan-14	Cycle - 1 Feb-14	Cycle - 1 Mar-14	Cycle - 1 Apr-14	Cycle - 1 May-14
1	**Beginning Balance (Overcollection)/Undercollection:**	**$ -**	**$ 920,756**	**$ 3,301,402**	**$ 5,128,809**	**$ 6,831,103**
2						
3	**Total Recorded Retail Revenues @ Meter Level**	$ 22,971,976	$ 24,531,023	$ 25,962,284	$ 26,153,852	$ 26,632,040
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 2 True-Up Adjustment.					
8						
9	**b) Amortization of Cycle 2 Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 2 Interest True-Up Adjustment.					
11						
12	**c) Amortization of TO3 Final True-Up Adjustment:**					
13	i. Amortization of TO3 Final True-Up Adjustment					
14						
15	**d) Amortization of Interest True-Up Adjustment on TO3 Final True-Up Adjustment:**					
16	i. Amortization of Interest True-Up Adjusment on TO3 Final True-Up Adjustment					
17						
18	Total Amortization of True-Up Adjustment & Interest True-Up Adjustment	$ -	$ -	$ -	$ -	$ -
19						
20	**Adjusted Total Recorded Retail Revenues @ Meter Level**	**$ 22,971,976**	**$ 24,531,023**	**$ 25,962,284**	**$ 26,153,852**	**$ 26,632,040**
21						
22	**Total True-Up Revenues (TU Cost of Service)**	**$ 23,891,490**	**$ 26,905,770**	**$ 27,778,345**	**$ 27,840,022**	**$ 28,284,941**
23						
24	**Net Monthly (Overcollection)/Undercollection:**	**$ 919,514**	**$ 2,374,747**	**$ 1,816,061**	**$ 1,686,170**	**$ 1,652,901**
25						
26	Interest Expense Calculations:					
27	Beginning Balance for Interest Calculation	$ -	$ -	$ -	$ 5,128,809	$ 5,128,809
28	Monthly Activity Included in Interest Calculation Basis	459,757	2,106,888	4,202,292	843,085	2,512,620
29	Basis for Interest Expense Calculation	459,757	2,106,888	4,202,292	5,971,894	7,641,429
30	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.27000%	0.28000%
31	**Interest Expense**	**$ 1,241**	**$ 5,899**	**$ 11,346**	**$ 16,124**	**$ 21,396**
32						
33	**Ending Balance (Overcollection)/Undercollection:**	**$ 920,756**	**$ 3,301,402**	**$ 5,128,809**	**$ 6,831,103**	**$ 8,505,400**
34						
35		Jan-14	Feb-14	Mar-14	Apr-14	May-14
36	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
37	Days in Year	365	365	365	365	365
38	Days in Month	30	31	30	31	31
39	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.27000%	0.28000%
40	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.27000%	0.28000%
41	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

Exhibit SDG-6-2
San Diego Gas Electric Co.
Illustration of RETAIL True-Up Adjustment Calculation

Line No.	TO4-Formula Cycle in Effect / Description	Cycle - 1 Jun-14	Cycle - 1 Jul-14	Cycle - 1 Aug-14	Cycle - 2 Sep-14	Cycle - 2 Oct-14
1	**Beginning Balance (Overcollection)/Undercollection:**	$ **8,505,400**	$ **7,404,628**	$ **1,294,412**	$ **(3,247,011)**	$ **(4,229,233)**
2						
3	**Total Recorded Retail Revenues @ Meter Level**	$ 33,362,799	$ 32,829,594	$ 30,307,336	$ 31,691,633	$ 31,586,810
4						
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**					
6	**a) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					
7	i. Amortization of Cycle 2 True-Up Adjustment.				(2,589,821)	(2,537,211)
8						
9	**b) Amortization of Cycle 2 Interest True-Up Adjustment:**					
10	i. Amortization of Cycle 2 Interest True-Up Adjustment.					
11						
12	**c) Amortization of TO3 Final True-Up Adjustment:**					
13	i. Amortization of TO3 Final True-Up Adjustment				(1,294,911)	(1,268,606)
14						
15	**d) Amortization of Interest True-Up Adjustment on TO3 Final True-Up Adjustment:**					
16	i. Amortization of Interest True-Up Adjusment on TO3 Final True-Up Adjustment					
17						
18	Total Amortization of True-Up Adjustment & Interest True-Up Adjustment	$ -	$ -	$ -	$ (3,884,732)	$ (3,805,817)
19						
20	**Adjusted Total Recorded Retail Revenues @ Meter Level**	$ **33,362,799**	$ **32,829,594**	$ **30,307,336**	$ **27,806,902**	$ **27,780,994**
21						
22	**Total True-Up Revenues (TU Cost of Service)**	$ **32,240,679**	$ **26,707,217**	$ **25,768,578**	$ **26,835,158**	$ **26,792,613**
23						
24	**Net Monthly (Overcollection)/Undercollection:**	$ **(1,122,120)**	$ **(6,122,377)**	$ **(4,538,758)**	$ **(971,744)**	$ **(988,380)**
25						
26	Interest Expense Calculations:					
27	Beginning Balance for Interest Calculation	$ 5,128,809	$ 7,404,628	$ 7,404,628	$ 7,404,628	$ (4,229,233)
28	Monthly Activity Included in Interest Calculation Basis	2,778,010	(3,061,189)	(8,391,756)	(11,147,007)	(494,190)
29	Basis for Interest Expense Calculation	7,906,819	4,343,439	(987,128)	(3,742,379)	(4,723,423)
30	Monthly Interest Rate	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
31	**Interest Expense**	$ **21,348**	$ **12,162**	$ **(2,665)**	$ **(10,479)**	$ **(13,226)**
32						
33	**Ending Balance (Overcollection)/Undercollection:**	$ **7,404,628**	$ **1,294,412**	$ **(3,247,011)**	$ **(4,229,233)**	$ **(5,230,839)**
34						
35		Jun-14	Jul-14	Aug-14	Sep-14	Oct-14
36	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%
37	Days in Year	365	365	365	365	365
38	Days in Month	30	31	30	31	31
39	Monthly Interest Rate - Calculated	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
40	FERC Interest Rates - Website	0.27000%	0.28000%	0.27000%	0.28000%	0.28000%
41	Difference	0.00000%	0.00000%	0.00000%	0.00000%	0.00000%

Exhibit SDG-6-2
San Diego Gas Electric Co.
Illustration of RETAIL True-Up Adjustment Calculation

Line No.	TO4-Formula Cycle in Effect / Description	Cycle - 2 Nov-14	Cycle - 2 Dec-14	Total	Reference	Line No.
1	**Beginning Balance (Overcollection)/Undercollection:**	$ **(5,230,839)**	$ **(5,927,695)**	$ -	Previous Month's Balance	1
2						2
3	**Total Recorded Retail Revenues @ Meter Level**	$ 29,202,549	$ 32,310,345	$ 347,542,241	Vol. 2; Section 2.2; Page 1; Line 11	3
4						4
5	**Amortization of True-Up Adjustment and Interest True-Up Adjustment:**				**SECTION 2.1A**	5
6	**a) Amortization of Cycle 2 True-Up Adjustment and Interest True-Up Adjustment:**					6
7	i. Amortization of Cycle 2 True-Up Adjustment.	(2,350,765)	(2,616,084)	(10,093,881)	See Related Work Papers	7
8						8
9	**b) Amortization of Cycle 2 Interest True-Up Adjustment:**					9
10	i. Amortization of Cycle 2 Interest True-Up Adjustment.			-	Amortization of Interest True-Up	10
11					adjustment will be reflected in TO4-Cycle 4.	11
12	**c) Amortization of TO3 Final True-Up Adjustment:**					12
13	i. Amortization of TO3 Final True-Up Adjustment	(1,175,383)	(1,308,042)	(5,046,941)	See Related Work Papers	13
14						14
15	**d) Amortization of Interest True-Up Adjustment on TO3 Final True-Up Adjustment:**					15
16	i. Amortization of Interest True-Up Adjusment on TO3 Final True-Up Adjustment			-	Amortization of Interest True-Up	16
17					adjustment will be reflected in TO4-Cycle 4.	17
18	Total Amortization of True-Up Adjustment & Interest True-Up Adjustment	$ (3,526,148)	$ (3,924,126)	$ (15,140,822)	Sum Lines 7 through 16	18
19						19
20	**Adjusted Total Recorded Retail Revenues @ Meter Level**	$ **25,676,402**	$ **28,386,219**	$ **332,401,420**	Sum Lines 3 & 18	20
21						21
22	**Total True-Up Revenues (TU Cost of Service)**	$ **24,993,998**	$ **26,708,189**	$ **324,747,000**	Section 2.3.2; Page 2; Line 11	22
23						23
24	**Net Monthly (Overcollection)/Undercollection:**	$ **(682,403)**	$ **(1,678,030)**	$ **(7,654,419)**	Line 22 Minus Line 20	24
25						25
26	Interest Expense Calculations:					26
27	Beginning Balance for Interest Calculation	$ (4,229,233)	$ (4,229,233)		Beginning Quarterly Balances	27
28	Monthly Activity Included in Interest Calculation Basis	(1,329,582)	(2,509,798)		Interest Calculation Basis	28
29	Basis for Interest Expense Calculation	(5,558,815)	(6,739,031)		Sum Lines 27 & 28	29
30	Monthly Interest Rate	0.26000%	0.28000%		FERC Monthly Rates	30
31	**Interest Expense**	$ **(14,453)**	$ **(18,869)**	$ **29,825**	Line 29 x Line 30	31
32						32
33	**Ending Balance (Overcollection)/Undercollection:**	$ **(5,927,695)**	$ **(7,624,594)**	$ **(7,624,594)**	Sum Lines 1; 24; & 31	33
34						34
35		Nov-14	Dec-14			35
36	FERC INTEREST RATE	3.25%	3.25%		Annual Interest Rate - FERC Website	36
37	Days in Year	365	365	365	Number of Days Per Year	37
38	Days in Month	29	31	366	Number of Days Per Month	38
39	Monthly Interest Rate - Calculated	0.26000%	0.28000%	3.29000%	(Line 36)/(Line 37)x(Line 38)	39
40	FERC Interest Rates - Website	0.26000%	0.28000%	3.29000%	Monthly Interest Rate - FERC Website	40
41	Difference	0.00000%	0.00000%	0.00000%	Line 39 - Line 40	41

WORK PAPER

Exhibit - SDG-6-2

Illustration – Derivation of Monthly True-Up Adjustment Amortization Calculation

Exhibit No. SDG-6-2 Work Paper
San Diego Gas Electric Co.
TO4-Cycle 3 Annual Transmission Formulaic Filing
Amortization Schedule of TO4-Cycle 2 True-Up Adjustment

Line No.	Description	(a) Amounts	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	**Derivation of Amortization Rates:**								
2	TO4-Cycle 2 Retail True-Up Adjustment	**$ 32,144,533**							
3	Forecast Sales TO4-Cycle 2 Net of Sale for Resale (kWh)	20,694,913,495							
4	Estimated Amortization Rate Per kWh	$ 0.00155							
5									
6									
7	**Derivation of Forecast Sales:** [1]	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15
8	Total Per TO4-Cycle 2 Filing - MWH (Statement BD)	1,946,695	1,712,997	1,667,110	1,718,629	1,770,104	1,662,031	1,643,248	1,581,745
9	Exclude Sale for Resale	2	2	2	2	2	2	2	2
10	Total Forecast Sales Net of Resale - MWH	1,946,693	1,712,996	1,667,108	1,718,628	1,770,103	1,662,030	1,643,246	1,581,743
11	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
12	Total Forecast Sales Net of Resale - kWh	1,946,693,495	1,712,995,645	1,667,108,057	1,718,627,828	1,770,102,954	1,662,029,725	1,643,246,433	1,581,743,038
13									
14									
15	**Amortization of TO4-Cycle 2 True-Up Adjustment:** [2]	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15
16	Beginning Retail True-Up Adjustment Balance	$ 32,144,533	$ 29,554,712	$ 27,017,501	$ 24,666,736	$ 22,050,652	$ 22,050,652	$ 22,050,652	$ 22,050,652
17	Recorded Sales in Total kWh	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	-	-	-	
18	Amortization Rate Per kWh	$ 0.00155	$ 0.00155	$ 0.00155	$ 0.00155	$ 0.00155	$ 0.00155	$ 0.00155	$ 0.00155
19	Amortization of TO4-Cycle 2 True-Up Adjustment [3]	**$ 2,589,821**	**$ 2,537,211**	**$ 2,350,765**	**$ 2,616,084**	$ -	$ -	$ -	$ -
20	Ending TO4-Cycle 2 True-Up Adjusment Balance	$ 29,554,712	$ 27,017,501	$ 24,666,736	$ 22,050,652	$ 22,050,652	$ 22,050,652	$ 22,050,652	$ 22,050,652
21									

NOTES:

1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.

2 On lines 16 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 17, to indicate the amortization of the true-up adjustment over the rate effective September 2014 through August 2015.

3 The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2014 through 12/31/2014 is included in the cycle 3 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in future TO4 filings.

Exhibit No. SDG-6-2 Work Paper
San Diego Gas Electric Co.
TO4-Cycle 3 Annual Transmission Formulaic Filing
Amortization Schedule of TO4-Cycle 2 True-Up Adjustment

Line No.	Description	(i)	(j)	(k)	(l)	(m)	Reference	Line No.
1	**Derivation of Amortization Rates:**							1
2	TO4-Cycle 2 Retail True-Up Adjustment						TO4-Cycle 2 Retail True-Up Adjustment	2
3	Forecast Sales TO4-Cycle 2 Net of Sale for Resale (kWh)						Forecast Sales TO4-Cycle 2 (kWh)	3
4	Estimated Amortization Rate Per kWh						Line 2 / Line 3	4
5								5
6								6
7	**Derivation of Forecast Sales:** [1]	May-15	Jun-15	Jul-15	Aug-15	Total		7
8	Total Per TO4-Cycle 2 Filing - MWH (Statement BD)	1,587,961	1,677,623	1,841,938	1,884,850	20,694,932	Forecast Sales TO4-Cycle 2 (kWh)	8
9	Exclude Sale for Resale	2	2	2	2	19	Sale for Resale	9
10	Total Forecast Sales Net of Resale - MWH	1,587,959	1,677,622	1,841,936	1,884,849	20,694,913	Line 8 Minus Line 9	10
11	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	MWH Conversion Factor	11
12	Total Forecast Sales Net of Resale - kWh	1,587,959,374	1,677,621,946	1,841,936,291	1,884,848,709	20,694,913,495	Line 10 x Line 11	12
13								13
14								14
15	**Amortization of TO4-Cycle 2 True-Up Adjustment:** [2]	May-15	Jun-15	Jul-15	Aug-15	Total		15
16	Beginning Retail True-Up Adjustment Balance	$ 22,050,652	$ 22,050,652	$ 22,050,652	$ 22,050,652		Beginning Balance	16
17	Recorded Sales in Total kWh					6,512,181,200	Recorded Sales (Sep. 2014 - Dec. 2014)	17
18	Amortization Rate Per kWh	$ 0.00155	$ 0.00155	$ 0.00155			See Line 4 Above	18
19	Amortization of TO4-Cycle 2 True-Up Adjustment [3]	$ -	$ -	$ -	$ 22,050,652	$ 32,144,533	Line 17 x Line 18	19
20	Ending TO4-Cycle 2 True-Up Adjusment Balance	$ 22,050,652	$ 22,050,652	$ 22,050,652	$ -		Line 16 Minus Line 19	20
21								21

NOTES:
1 The derivation of forecast sales shown on lines 8 through 12 indicates the forecast sales used on line 3 to develop the amortization rate during the rate effective period.
2 On lines 16 through 20, SDG&E is taking the product between the amortization rate on line 4 and the recorded sales on 17, to indicate the amortization of the true-up adjustment over the rate effective September 2014 through August 2015.
3 The monthly true-up adjustment amortization amount shown on line 19 from 9/1/2014 through 12/31/2014 is included in the cycle 3 true-up adjustment period. Future monthly amortization amounts have not been shown since the amounts will be shown in future TO4 filings.

Exhibit - SDG-6-3

Illustration – Interest True-Up Adjustment Calculation

Exhibit SDG-6-3
San Diego Gas and Electric Company
Illustration of Interest True-Up Adjustment Applicable to TO4-Cycle 2
TO4-Cycle 3 Annual Formula Filing

Line No.	Description	(a) Jan-14	(b) Feb-14	(c) Mar-14	(d) Apr-14	(e) May-14	(f) Jun-14	(g) Jul-14	(h) Aug-14
		C1	C1	C1	C1	C1	C1	C1	C1
1	**Beginning Balance (Overcollection)/Undercollection TO4-C2**	$ 32,144,533	$ 32,231,323	$ 32,321,328	$ 32,408,118	$ 32,495,620	$ 32,586,363	$ 32,673,865	$ 32,765,352
2									
3	**Part A1: Amortization of TU Balance:**								
4	Total Recorded Sales KWHs	-	-	-	-	-	-	-	-
5									
6	Rate Per KWH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7									
8	Amortization of True-Up Balance	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9									
10	Net Monthly Collection/(Refunds)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11									
12	**Part A2: Calculation of Interest on Remaining TU Balance:**								
13	Interest Expense Calculations: [1]								
14	Beginning Balance for Interest Calculation	$ 32,144,533	$ 32,144,533	$ 32,144,533	$ 32,408,118	$ 32,408,118	$ 32,408,118	$ 32,673,865	$ 32,673,865
15	Monthly Activity Included in Interest Calculation Basis [2]	0	0	0	0	0	0	0	0
16	Basis for Interest Expense Calculation	32,144,533	32,144,533	32,144,533	32,408,118	32,408,118	32,408,118	32,673,865	32,673,865
17	Monthly Interest Rate	0.27%	0.28%	0.27%	0.27%	0.28%	0.27%	0.28%	0.27%
18	Interest Expense	**$ 86,790**	**$ 90,005**	**$ 86,790**	**$ 87,502**	**$ 90,743**	**$ 87,502**	**$ 91,487**	**$ 88,219**
19									
20	Ending Balance (Overcollection)/Undercollection	$ 32,231,323	$ 32,321,328	$ 32,408,118	$ 32,495,620	$ 32,586,363	$ 32,673,865	$ 32,765,352	$ 32,853,571
21		Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14
22	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
23	Days in Year	365	365	365	365	365	365	365	365
24	Days in Month	30	31	30	31	31	30	31	30
25	Monthly Interest Rate - Calculated	0.27%	0.28%	0.27%	0.27%	0.28%	0.27%	0.28%	0.27%
26	FERC Interest Rates - Website	0.27%	0.28%	0.27%	0.27%	0.28%	0.27%	0.28%	0.27%
27	Difference	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 Month Quarter as Interest is Compounded Quarterly on these amounts pursuant to FERC Interest Methodology - per 18 CFR Section 35.19 (2) (iii) (B)

2 Monthly Activity Calculated as Follows:
a) 1st Month of Quarter = Column A, Line 15 Divided by 2
b) 2nd Month of Quarter = Column A, Line 15 + (Column B, Line 15 Divided by 2)
c) 3rd Month of Quarter = Column A, Line 15 + Column B, Line 15 + (Column C, Line 15 Divided by 2). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

Exhibit SDG-6-3
San Diego Gas and Electric Company
Illustration of Interest True-Up Adjustment Applicable to TO4-Cycle 2
TO4-Cycle 3 Annual Formula Filing

Line No.	Description	(i) Sep-14	(j) Oct-14	(k) Nov-14	(l) Dec-14	(m) Total	Reference	Line No.
		C2	C2	C2	C2			
1	**Beginning Balance (Overcollection)/Undercollection TO4-C2**	$ 32,853,571	$ 30,284,684	$ 27,763,150	$ 25,420,558	$ 32,144,533	Previous Month's Ending Balance (Line 22)	1
2								2
3	**Part A1: Amortization of TU Balance:**							3
4	Total Recorded Sales KWHs	1,670,852,042	1,636,910,207	1,516,622,552	1,687,796,399	6,512,181,200	Recorded Sales	4
5								5
6	Rate Per KWH	$ 0.00159	$ 0.00159	$ 0.00159	$ 0.00159		Amortization Rate	6
7								7
8	Amortization of True-Up Balance	$ 2,656,655	$ 2,602,687	$ 2,411,430	$ 2,683,596	$ 10,354,368	Line 6 x Line 8	8
9								9
10	Net Monthly Collection/(Refunds)	$ (2,656,655)	$ (2,602,687)	$ (2,411,430)	$ (2,683,596)	$ (10,354,368)	Minus Line 10 (Columns a to l)	10
11								11
12	**Part A2: Calculation of Interest on Remaining TU Balance:**							12
13	Interest Expense Calculations: [1]							13
14	Beginning Balance for Interest Calculation	$ 32,673,865	$ 30,284,684	$ 30,284,684	$ 30,284,684		Balance at Beginning of Quarter (See Footnote 1)	14
15	Monthly Activity Included in Interest Calculation Basis [2]	(1,328,328)	(1,301,344)	(3,808,402)	(6,355,915)		See Footnote 2	15
16	Basis for Interest Expense Calculation	31,345,538	28,983,341	26,476,282	23,928,769		Line 16 + Line 17	16
17	Monthly Interest Rate	0.28%	0.28%	0.26%	0.28%		FERC Monthly Rates	17
18	Interest Expense	**$ 87,768**	**$ 81,153**	**$ 68,838**	**$ 67,001**	**$ 1,013,798**	Line 18 x Line 19 (Columns a to l)	18
19								19
20	Ending Balance (Overcollection)/Undercollection	$ 30,284,684	$ 27,763,150	$ 25,420,558	$ 22,803,963	$ 22,803,963	Line 1 + Line 12 + Line 20	20
21		Sep-14	Oct-14	Nov-14	Dec-14			21
22	FERC INTEREST RATE	3.25%	3.25%	3.25%	3.25%		Annual Interest Rate - FERC Website	22
23	Days in Year	365	365	366	365	365	Number of Days Per Year	23
24	Days in Month	31	31	29	31	366	Number of Days Per Month	24
25	Monthly Interest Rate - Calculated	0.28%	0.28%	0.26%	0.28%	3.29%	(Line 24)/(Line 25)x(Line 26)	25
26	FERC Interest Rates - Website	0.28%	0.28%	0.26%	0.28%	3.29%	Monthly Interest Rate - FERC Website	26
27	Difference	0.00%	0.00%	0.00%	0.00%	0.00%	Line 27 - Line 28	27

NOTES:

1 Beginning Balance for Interest Calculation Remains Constant for 3 Month Quarter as Interest is Compounded Quarterly on these amounts pursuant to FERC Interest Methodology - per 18 CFR Section 35.19 (2) (iii) (B)

2 Monthly Activity Calculated as Follows:

a) 1st Month of Quarter = Column A, Line 15 Divided by 2
b) 2nd Month of Quarter = Column A, Line 15 + (Column B, Line 15 Divided by 2)
c) 3rd Month of Quarter = Column A, Line 15 + Column B, Line 15 + (Column C, Line 15 Divided by 2). Column D, E, F, etc. repeats the process outlined in (a), (b), and (c) above.

WORK PAPER

Exhibit - SDG-6-3

Illustration – Derivation of True-Up Adjustment Amortization Rate to Derive the Interest True-Up Adjustment

Exhibit No. SDG-6-3 Work Paper
San Diego Gas Electric Company
TO4 Cycle 3 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO4 Cycle 2

Line No.	Description	(a) Sep-14	(b) Oct-14	(c) Nov-14	(d) Dec-14	(e) Jan-15	(f) Feb-15	(g) Mar-15	(h) Apr-15
1	**Derivation of Amortization Rate for TO4-Cycle 3:**								
2	Beginning Balance (Overcollection)/Undercollection								
3	Including Accrued Interest from end of True-Up Period								
4	Until the Beginning of Rate Effective Period.								
5									
6	**Derivation of Forecast Sales:** [1]	Sep-14	Oct-14	Nov-14	Dec-14	Jan-15	Feb-15	Mar-15	Apr-15
7	Total Per TO4-Cycle 2 Filing - MWH (Statement BD)	1,946,695	1,712,997	1,667,110	1,718,629	1,770,104	1,662,031	1,643,248	1,581,745
8	Exclude Sale for Resale	2	2	2	2	2	2	2	2
9	Total Forecast Sales Net of Resale - MWH	1,946,693	1,712,996	1,667,108	1,718,628	1,770,103	1,662,030	1,643,246	1,581,743
10	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
11	Total Forecast Sales Net of Resale - kWh	1,946,693,495	1,712,995,645	1,667,108,057	1,718,627,828	1,770,102,954	1,662,029,725	1,643,246,433	1,581,743,038
12									
13	Interest True-Up Adjustment Amortization Rate Per kWh								
14									

Exhibit No. SDG-6-3 Work Paper
San Diego Gas Electric Company
TO4 Cycle 3 Annual Transmission Formula Filing
Derivation of Amortization Rate for TO4 Cycle 2

Line No.	Description	(i) May-15	(j) Jun-15	(k) Jul-15	(l) Aug-15	(m) Total	Reference	Line No.
1	**Derivation of Amortization Rate for TO4-Cycle 3:**						From TO4-Cycle 2 Filing.	1
2	Beginning Balance (Overcollection)/Undercollection					$ 32,853,571	For Illustrative Purposes Only	2
3	Including Accrued Interest from end of True-Up Period							3
4	Until the Beginning of Rate Effective Period.							4
5								5
6	**Derivation of Forecast Sales:** [1]	May-15	Jun-15	Jul-15	Aug-15	Total		6
7	Total Per TO4-Cycle 2 Filing - MWH (Statement BD)	1,587,961	1,677,623	1,841,938	1,884,850	20,694,932		7
8	Exclude Sale for Resale	2	2	2	2	19		8
9	Total Forecast Sales Net of Resale - MWH	1,587,959	1,677,622	1,841,936	1,884,849	20,694,913	TO4-Cycle 2; Forecast Sales	9
10	Conversion Factor from MWH to kWh	1,000	1,000	1,000	1,000	1,000	Excluding Sales for Resales	10
11	Total Forecast Sales Net of Resale - kWh	1,587,959,374	1,677,621,946	1,841,936,291	1,884,848,709	20,694,913,495	For Illustrative Purposes Only	11
12								12
13	Interest True-Up Adjustment Amortization Rate Per kWh					$ 0.00159	Line 2 / Line 9	13
14								14

Exhibit - SDG-6-4

Cost Statement Modifications to Incorporation Order 679 Incentives into the Transmission Formula

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AD
Cost of Plant
Base Period 12 - Months Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-4
Page 1 of 7

Line No		Amount	Reference	Line No
1	Transmission Electric Miscellaneous Intangible Plant [1,2]	$ 5,982	Stmnt AD WP; Page-AD1; Line 1	1
2				2
3	Total Steam Production Plant	440,146	Stmnt AD WP; Page-AD1; Line 3	3
4				4
5	Total Nuclear Production Plant	1,462,374	Stmnt AD WP; Page-AD1; Line 5	5
6				6
7	Total Hydraulic Production Plant	-	Stmnt AD WP; Page-AD1; Line 7	7
8				8
9	Total Other Production Plant	399,705	Stmnt AD WP; Page-AD1; Line 9	9
10				10
11	Total Production Plant and Intangible plant	$ 2,308,207	Sum Lines 1 thru 9	11
12				12
13	Total Distribution Plant	4,752,127	Stmnt AD WP; Page-AD1; Line 13	13
14				14
15	Transmission Plant [3]	1,785,708	Stmnt AD WP; Page-AD1; Line 15	15
16				16
17	**Transmission Incentive Plant [4]**	**250,000**	**Stmnt AD WP; Page-AD1; Line 17**	17
18				18
19	Total Transmission Plant	$ 2,035,708	Sum Lines 15; 17	19
20				20
21	Total General Plant [1]	202,109	Stmnt AD WP; Page-AD1; Line 21	21
22				22
23	Total Common Plant [1]	470,816	Stmnt AD WP; Page-AD1; Line 23	23
24				24
25	Total Plant in Service	$ 9,768,968	Sum Lines 11; 13; 19; 21; 23	25
26				26
27	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	27
28				28
29	Transmission Electric Miscellaneous Intangible Plant	$ 5,982	See Line 1 Above	29
30				30
31	Transmission Plant	2,035,708	See Line 19 Above	31
32				32
33	Transmission Related General Plant	29,185	Line 21 x Line 27	33
34				34
35	Transmission Related Common Plant	67,986	Line 23 x Line 27	35
36				36
37	Transmission Related Total Plant in Service	$ 2,138,861	Sum Lines 29; 31; 33; 35	37
38				38
39	Transmission Plant Allocation Factor [5]	21.89%	Line 37 / Line 25	39

NOTES:

1 Electric Miscellaneous Intangible Plant, General Plant, and Common Plant have a Seven Element Adjustment Factor of "1" because there is no transfer of transmission or distribution plant among these categories.

2 Transmission Electric Miscellaneous Intangible Plant consist of only those directly assigned to transmission and is not subject to labor ratio.

3 The amounts stated above are ratemaking utility plant in service and are derived by multiplying the book utility plant in service by the FERC's Seven Element Adjustment Factors.

4 The purpose of this footnote is to indicate for incentive projects, the cost of the project, and the in-service-date of incentive projects. There were no incentive projects included in Cycle 1 of SDG&E's TO-4 transmission rate case filing.

5 Used to allocate all elements of working capital, other than working cash.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AE
Accumulated Depreciation and Amortization
Base Period 12 - Months Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-4
Page 2 of 7

Line No		Amounts	Reference	Line No
1	Transmission Plant Accumulated Depreciation Reserve [1]	$ 528,768	Stmnt AE WP; Page-AE1; Line 1	1
2				2
3	**Incentive Transmission Plant Accumulated Depreciation Reserve**	**6,625**	**Stmnt AE WP; Page-AE1; Line 3**	3
4				4
5	Total Transmission Accumulated Depreciation Reserve	$ 535,393	Sum Lines 1; 3	5
6				6
7	Transmission Electric Miscellaneous Intangible Plant Amortization Reserve [2,3]	4,948	Stmnt AE WP; Page-AE1; Line 7	7
8				8
9	General Plant Accumulated Depreciation Reserve [2]	87,260	Stmnt AE WP; Page-AE1; Line 9	9
10				10
11	Common Plant Accumulated Depreciation Reserve [2]	242,587	Stmnt AE WP; Page-AE1; Line 11	11
12				12
13	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	13
14				14
15	Transmission Related General Plant Accumulated Depreciation Reserve	12,600	Line 9 x Line 13	15
16				16
17	Transmission Related Common Plant Accumulated Depreciation Reserve	35,030	Line 11 x Line 13	17
18				18
19	Total Transmission Related Accumulated Depreciation Reserve	$ 587,971	Sum Lines 5; 7; 15; 17	19

NOTES:

1 The amounts stated above are ratemaking utility plant in service and are derived by multiplying the book utility plant in service by the FERC's Seven Element Adjustment Factors.

2 Electric Miscellaneous Intangible Plant, General Plant, and Common Plant have a Seven Element Adjustment Factor of "1" because there is no transfer of transmission or distribution plant to these categories.

3 Transmission Electric Miscellaneous Intangible Plant consist of only those directly assigned to transmission and is not subject to labor ratio.

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AF
Deferred Credits
Base Period 12 - Months Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-4
Page 3 of 7

Line No		Amounts	Reference	Line No
1	Transmission Plant Related ADIT- Excluding Bonus Depreciation	$ (151,843)	Stmnt AF WP; Page-AF1; Line 1	1
2				2
3	Transmission Plant Related ADIT from Bonus Depreciation	(32,324)	Stmnt AF WP; Page-AF1; Line 3	3
4				4
5	Total Transmission Plant Related ADIT	$ (184,167)	Sum Lines 1 thru 3	5
6				6
7	**Incentive Transmission Plant Related ADIT**	**(2,500)**	**Stmnt AF WP; Page-AF1; Line 7**	7
8				8
9	Total	$ (186,667)	Sum Lines 5 thru 7	9

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AJ
Depreciation and Amortization Expense
Base Period 12 - Months Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-4
Page 4 of 7

Line No.		Amounts	Reference	Line No.
1	Transmission Depreciation Expense	$ 46,762	Stmnt AJ WP; Page-AJ1; Line 1	1
2				2
3	**Transmission Incentive Depreciation Expense**	-	**Stmnt AJ WP; Page-AJ1; Line 3**	3
4				4
5	Total Transmission Plant Depreciation Expense	46,762	Sum Lines 1 thru 3	5
6				6
7	Transmission Electric Miscellaneous Intangible Plant Amortization Expense	261	Stmnt AJ WP; Page-AJ1; Line 7	7
8				8
9	General Plant Depreciation Expense	9,082	Stmnt AJ WP; Page-AJ1; Line 9	9
10				10
11	Common Plant Depreciation Expense	44,477	Stmnt AJ WP; Page-AJ1; Line 11	11
12				12
13	Transmission Wages and Salaries Allocation Factor	14.44%	Statement AI; Line 13	13
14				14
15	Transmission Related General Plant Depreciation Expense	1,311	Line 9 x Line 13	15
16				16
17	Transmission Related Common Plant Depreciation Expense	6,422	Line 11 x Line 13	17
18				18
19	Total Transmission, Intangible, Gen. and Comm. Depr. & Amort. Exp.	$ 54,756	Sum Lines 1; 7; 15; 17	19
20				20
21	**Incentive Transmission, Intangible, Gen. and Comm. Depr. & Amort. Exp.**	**$ 6,625**	**Stmnt AJ WP; Page-AJ1; Line 21**	21
22				22
23	Valley Rainbow Project Cost Amortization Expense	$ 1,893	Stmnt AJ WP; Page-AJ1; Line 23	23
24				24
25	Transmission Abandoned Project Cost Amortization Expense	$ -	Stmnt AJ WP; Page-AJ1; Line 25	25

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
Base Period 12 - Months Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
1	Long-Term Debt Component - Denominator:			1
2	(Plus): Account 221 - Bonds	$ 3,536,905	Stmnt AV WP; Page-AV1; Line 2	2
3	(Less): Account 222 - Reacquired Bonds	-	Stmnt AV WP; Page-AV1; Line 3	3
4	(Plus): Account 224 - Other Long-Term Debt (Acct. 224)	253,720	Stmnt AV WP; Page-AV1; Line 4	4
5	(Plus): Account 225 - Unamortized Premium on Long-Term Debt	-	Stmnt AV WP; Page-AV1; Line 5	5
6	(Less): Account 226 - Unamortized Discount on Long-Term Debt-Debit	12,055	Stmnt AV WP; Page-AV1; Line 6	6
7	Total Long Term Debt (LTD)	$ 3,778,570	Line 2 Minus Line 3 Plus Lines 4 & 5 Minus Line 6	7
8				8
9	Long-Term Debt Component - Numerator:			9
10	(Plus): Account 427 - Interest on Long-Term Debt	$ 163,736	Stmnt AV WP; Page-AV1; Line 10	10
11	(Plus): Account 428 - Amort. of Debt Disc. and Expense	2,607	Stmnt AV WP; Page-AV1; Line 11	11
12	(Plus): Account 428.1 - Amortization of Loss on Reacquired Debt	3,388	Stmnt AV WP; Page-AV1; Line 12	12
13	(Less): Account 429 - Amort. of Premium on Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 13	13
14	(Less): Account 429.1 - Amortization of Gain on Reacquired Debt-Credit	-	Stmnt AV WP; Page-AV1; Line 14	14
15	Total LTD Interest = (i)	$ 169,731	Sum Lines 10; 11; 12 Minus Lines 13 & 14	15
16				16
17	Cost of Long-Term Debt:	4.49%	Line 15 / Line 7	17
18				18
19				19
20	Preferred Equity Component:			20
21	PF = Preferred Stock - Account 204	$ 78,475	Stmnt AV WP; Page-AV1; Line 21	21
22	d(pf) = Total Dividends Declared-Preferred Stocks - Account 437	4,820	Stmnt AV WP; Page-AV1; Line 22	22
23	Cost of Preferred Equity	6.14%	Line 22 / Line 21	23
24				24
25				25
26	Common Equity Component:			26
27	Proprietary Capital	$ 3,990,776	Stmnt AV WP; Page-AV1; Line 27	27
28	(Less): Account 204 Preferred Stock	78,475	Stmnt AV WP; Page-AV1; Line 28	28
29	(Less): Account 216.1 Unappropriated Undistributed Subsidiary Earnings	-	Stmnt AV WP; Page-AV1; Line 29	29
30	CS = Common Stock	$ 3,912,301	Line 27 Minus Lines 28 & 29	30
31				31

Line No.		(a) Amount	(b) Cap. Struct. Ratio	(c) Cost of Capital	(d) = (b) x (c) Weighted Cost of Capital	Reference	Line No.
32	Return on Common Equity				11.30%	Stmnt AV WP; Page-AV1; Line 32	32
33		(a)	(b)	(c)	(d) = (b) x (c)		33
34			Cap. Struct.		Weighted		34
35	Weighted Cost of Capital:	Amount	Ratio	Cost of Capital	Cost of Capital		35
36							36
37	Long-Term Debt	$ 3,778,570	48.63%	4.49%	2.18%	Col. C = Line 17 Above	37
38	Preferred Equity	78,475	1.01%	6.14%	0.06%	Col. C = Line 23 Above	38
39	Common Equity	3,912,301	50.36%	11.30%	5.69%	Col. C = Line 32 Above	39
40	Total Capital	$ 7,769,346	100.00%		7.93%	Sum Lines 37 thru 39	40
41							41
42							42
43	Cost of Equity Component (Preferred & Common):				5.75%	Sum Lines 38; 39	43
44							44

Line No.		(a) Amount	(b) Cap. Struct. Ratio	(c) Cost of Capital	(d) = (b) x (c) Weighted Cost of Capital	Reference	Line No.
45	**Incentive Return on Common Equity**				**12.30%**	**For Illustrative Purposes Only**	45
46		(a)	(b)	(c)	(d) = (b) x (c)		46
47			Cap. Struct.		Weighted		47
48	Weighted Cost of Capital:	Amount	Ratio	Cost of Capital	Cost of Capital		48
49							49
50	Long-Term Debt	$ 3,778,570	48.63%	4.49%	2.18%	TO4-Cycle 1 - For Illustration Purposes Only	50
51	Preferred Equity	78,475	1.01%	6.14%	0.06%	TO4-Cycle 1 - For Illustration Purposes Only	51
52	Common Equity	3,912,301	50.36%	12.30%	6.19%	TO4-Cycle 1 - For Illustration Purposes Only	52
53	Total Capital	$ 7,769,346	100.00%		8.43%	Sum Lines 50 thru 52	53
54							54
55							55
56	Cost of Equity Component (Preferred & Common):				6.25%	Sum Lines 51; 52	56

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV
Cost of Capital and Fair Rate of Return
Base Period 12 - Months Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-4
Page 6 of 7

Line No.			Amounts	Reference	Line No.
1	Cost of Capital Rate $_{(COCR)}$ Calculation:				1
2					2
3	a) Federal Income Tax Component:				3
4					4
5	Where:				5
6	A = Sum of Preferred Stock and Return on Equity Component		5.75%	Statement AV; Page 13; Line 43	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		8
9	D = Transmission Rate Base	$	1,220,533	Statement BK1; Page 2; Line 20	9
10	FT = Federal Income Tax Rate July 1, 2012		35%	Federal Income Tax Rate	10
11					11
12	Federal Income Tax = (A + [(C - B) / D]) (FT) =		3.0845%	Federal Income Tax Expense	12
13	1 - FT				13
14					14
15					15
16	b) State Income Tax Component:				16
17					17
18	Where:				18
19	A = Sum of Preferred Stock and Return on Equity Component		5.75%	Statement AV; Page 13; Line 43	19
20	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	20
21	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		21
22	D = Transmission Rate Base	$	1,220,533	Statement BK1; Page 2; Line 20	22
23	FT = Federal Income Tax Expense		3.0845%	Line 12 Above	23
24	ST = State Income Tax Rate July 1, 2012		8.84%	State Income Tax Rate	24
25					25
26	State Income Tax = (A + [(C - B) / D] + Federal Income Tax) (ST) =		0.8546%	State Income Tax Expense	26
27	1 - ST				27
28					28
29	c) Total Federal & State Income Tax Expense:		3.9391%	Sum Lines 12; 26	29
30					30
31	d) Total Weighted Cost of Capital:		7.9300%	Statement AV; Page 13; Line 40	31
32					32
33	e) Cost of Capital Rate $_{(COCR)}$:		11.8691%	Sum Lines 29; 31	33

Exhibit No. SDG-6-4
Page 7 of 7

Line No.			Reference	Amounts	Line No.
1	**Incentive Cost of Capital Rate $_{(ICOCR)}$ Calculation:**				1
2					2
3	a) Federal Income Tax Component:				3
4					4
5	Where:				5
6	A = Sum of Preferred Stock and Return on Equity Component		6.25%	Statement AV; Page 13; Line 56	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		8
9	D = Incentive Transmission Rate Base	$	290,875	Statement BK1; Page 2; Line 34	9
10	FT = Federal Income Tax Rate July 1, 2012		35%	Federal Income Tax Rate	10
11					11
12	Federal Income Tax = (A + [(C - B) / D]) (FT) =		3.3163%	Federal Income Tax - Not Applicable in TO4-Cycle 1	12
13	1 - FT				13
14					14
15					15
16	b) State Income Tax Component:				16
17					17
18	Where:				18
19	A = Sum of Preferred Stock and Return on Equity Component		6.25%	Statement AV; Page 13; Line 56	19
20	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$	265	Statement AR; Page 11; Line 5	20
21	C = Equity AFUDC Component of Transmission Depreciation Expense	$	-		21
22	**D = Incentive Transmission Rate Base (CWIP + Plant in Service)**	$	290,875	Statement BK1; Page 2; Line 34	22
23	FT = Federal Income Tax Expense		3.3163%	Line 12 Above	23
24	ST = State Income Tax Rate July 1, 2012		8.84%	State Income Tax Rate	24
25					25
26	State Income Tax = (A + [(C - B) / D] + Federal Income Tax) (ST) =		0.9188%	State Income Tax - Not Applicable in TO4-Cycle 1	26
27	1 - ST				27
28					28
29	c) Total Federal & State Income Tax Expense:		4.2352%	Sum Lines 12; 26	29
30					30
31	d) Total Weighted Cost of Capital:		8.4300%	Statement AV; Page 13; Line 53	31
32					32
33	**e) Incentive Cost of Capital Rate $_{(ICOCR)}$:**		**12.6652%**	**Sum Lines 29; 31**	33

Exhibit - SDG-6-5

Illustrative Example of Statement BK-1 Cost of Service to Incorporation Order 679 Incentives into the Transmission Formula

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-5
Page 1 of 6

Line No.		Amounts	Reference	Line No.
1	**A. Revenues:**			1
2	Transmission Operation & Maintenance Expense	$ 48,715	Statement AH; Page 5, Line 8	2
3				3
4	Transmission Related A&G Expenses	42,317	Statement AH; Page 5, Line 57	4
5				5
6	CPUC Intervenor Funding Expense	-	Statement AH; Page 5, Line 9	6
7				7
8	Total O&M Expenses	$ 91,032	Sum Lines 2 thru 6	8
9				9
10	Transmission, Intangible, General and Common Depr. & Amort. Expense	54,756	Statement AJ; Page 7, Line 19	10
11				11
12	Valley Rainbow Project Cost Amortization Expense	1,893	Statement AJ; Page 7, Line 23	12
13				13
14	Transmission Abandoned Project Cost Amortization Expense	-	Statement AJ; Page 7, Line 25	14
15				15
16	Transmission Related Property Taxes Expense	12,282	Statement AK; Page 8, Line 27	16
17				17
18	Transmission Related Payroll Taxes Expense	2,030	Statement AK; Page 8, Line 34	18
19				19
20	Sub-Total Expense	$ 161,993	Sum Lines 8 thru 18	20
21				21
22	Cost of Capital Rate $_{(COCR)}$	11.8691%	Statement AV; Page 14, Line 33	22
23				23
24	Transmission Rate Base	$ 1,220,533	Statement BK-1; Page 2, Line 20	24
25				25
26	Return and Associated Income Taxes	$ 144,866	Line 22 x Line 24	26
27				27
28	South Georgia Income Tax Adjustment	2,333	Statement AQ; Page 10, Line 1	28
29	Transmission Related Amortization of ITC	(265)	Statement AR; Page 11, Line 1	29
30	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement AR; Page 11, Line 3	30
31	Transmission Related Revenue Credits	(2,652)	Statement AU; Page 12, Line 11	31
32	Transmission Related Regulatory Debits	-	Not Applicable in TO4-Cycle 1	32
33	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement AU; Page 12, Line 13	33
34				34
35	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$ 306,275	Line 20 + Sum Lines (26 thru 33)	35
36				36
37	**B. Incentive Revenues:**			37
38	**Incentive Transmission Plant Depreciation Expense**	**$ 6,625**	**Statement AJ; Page 7; Line 21**	38
39	**Sub-Total Expense**	**$ 6,625**	**Sum Lines 38**	39
40				40
41	**Incentive Cost of Capital Rate $_{(ICOCR)}$**	**12.6652%**	**Statement AV; Page 15; Line 33**	41
42	**Incentive Transmission Rate Base**	**$ 290,875**	**Statement BK-1; Page 2; Line 34**	42
43				43
44	**Incentive Return and Associated Income Taxes**	**$ 36,840**	**Line 41 x Line 42**	44
45				45
46	**Incentive End of Prior Year Revenues (PYRR $_{EU-IR}$) Excluding FF&U**	**$ 43,465**	**Sum Lines 39; 44**	46
47				47
48	**C. Total (PYRR $_{EU}$) Excluding FF&U [1]**	$ 349,740	Sum Lines 35; 46	48

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for 12 months ending May 31, 2012.

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Rate Base			
1	Net Transmission Plant:			1
2	Transmission Plant	$ 1,256,940	Statement BK-1; Page 3; Line 16	2
3	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Statement BK-1; Page 3; Line 17	3
4	Transmission Related General Plant	16,585	Statement BK-1; Page 3; Line 18	4
5	Transmission Related Common Plant	32,956	Statement BK-1; Page 3; Line 19	5
6	Total Net Transmission Plant	$ 1,307,515	Sum Lines 2 thru 5	6
7				7
8	Rate Base Additions:			8
9	Transmission Plant Held for Future Use	$ 66,487	Statement AG; Page 4; Line 3	9
10	Transmission Abandoned Project Cost	-	Not Applicable in TO4-Cycle 1	10
11	Total Rate Base Additions	$ 66,487	Sum Lines 9 thru 10	11
12				12
13	Rate Base Reductions:			13
14	Transmission Related Accum. Def. Inc. Taxes	$ (184,167)	Statement AF; Page 3; Line 5	14
15	Transmission Related Abandoned Accum. Def. Inc. Taxes	-	Not Applicable in TO4-Cycle 1	15
16	Total Rate Base Reductions	$ (184,167)	Sum Lines 14 thru 15	16
17				17
18	Working Capital:			18
19	Transmission Related Material and Supplies	$ 12,443	Statement AL; Page 9; Line 5	19
20	Transmission Related Prepayments	6,876	Statement AL; Page 9; Line 9	20
21	Transmission Related Cash Working Capital	11,379	Statement AL; Page 9; Line 19	21
22	Total Working Capital	$ 30,698	Sum Lines 19 thru 21	22
23				23
24	Other Regulatory Assets/Liabilities	-	Not Applicable in TO4-Cycle 1	24
25				25
26	Total Transmission Rate Base	$ 1,220,533	Sum Lines 6; 11; 16; 22; 24	26
27				27
28	**B. Incentive Transmission Rate Base**			28
29	**Net Incentive Transmission Plant**	**$ 243,375**	**Statement BK-1; Page 3; Line 25**	29
30				30
31	**Rate Base Addition:**			31
32	**Transmission Construction Work In Progress for Incentive Projects**	**$ 50,000**	**For Illustrative Purposes - (Cost Statement M)**	32
33	**Total Rate Base Addition**	**$ 50,000**	**Sum Line 32**	33
34				34
35	**Rate Base Reduction:**			35
36	**Incentive Transmission Plant Related Accum. Def. Income Taxes**	**$ (2,500)**	**Statement AF; Page 3; Line 7**	36
37	**Total Rate Base Reduction**	**$ (2,500)**	**Sum Line 36**	37
38				38
39	**Total Incentive Transmission Rate Base**	**$ 290,875**	**Sum Lines 29; 33; 37**	39

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Prior Year Revenue Requirements (PYRR $_{EU}$)
For the Base Period Ending May 31, 2012
($1,000)

Line No.		Amounts	Reference	Line No.
	A. Transmission Plant			
1	Gross Transmission Plant:			1
2	Transmission Plant	$ 1,785,708	Statement AD; Page 1, Line 31	2
3	Transmission Related Electric Miscellaneous Intangible Plant	5,982	Statement AD; Page 1, Line 29	3
4	Transmission Related General Plant	29,185	Statement AD; Page 1, Line 33	4
5	Transmission Related Common Plant	67,986	Statement AD; Page 1, Line 35	5
6	Total Gross Transmission Plant	$ 1,888,861	Sum Lines 2 thru 5	6
7				7
8	Accumulated Depreciation Reserve:			8
9	Transmission Plant Depreciation Reserve	$ 528,768	Statement AE; Page 2, Line 1	9
10	Transmission Related Electric Miscellaneous Intangible Amortization Reserve	4,948	Statement AE; Page 2, Line 7	10
11	Transmission Related General Plant Depr Reserve	12,600	Statement AE; Page 2, Line 15	11
12	Transmission Related Common Plant Depr Reserve	35,030	Statement AE; Page 2, Line 17	12
13	Total Transmission Related Accumulated Depreciation Reserve	$ 581,346	Sum Lines 9 thru 12	13
14				14
15	Net Transmission Plant:			15
16	Transmission Plant	$ 1,256,940	Line 2 Minus Line 9	16
17	Transmission Related Electric Miscellaneous Intangible Plant	1,034	Line 3 Minus Line 10	17
18	Transmission Related General Plant	16,585	Line 4 Minus Line 11	18
19	Transmission Related Common Plant	32,956	Line 5 Minus Line 12	19
20	Total Net Transmission Plant	$ 1,307,515	Sum Lines 16 thru 19	20
21				21
22	**B. Incentive Transmission Plant**			22
23	**Incentive Transmission Plant**	**$ 250,000**	**Statement AD; Page 1, Line 17**	23
24	**Incentive Transmission Related Accumulated Depreciation Reserve**	**6,625**	**Statement AE; Page 2, Line 3**	24
25	**Total Net Incentive Transmission Plant**	**$ 243,375**	**Line 23 Minus Line 24**	25

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC_{EU})
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate ($AFCR_{EU}$) Applicable to**			1
2	**Weighted Forecast Plant Additions:**			2
3	$PYRR_{EU}$ Excluding Franchise Fees and Uncollectible	$ 306,275	Statement BK-1; Page 1; Line 35	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	(Gains)/Losses from Sale of Plant Held for Future Use	-	Statement BK-1; Page 1; Line 33	9
10	Total (PYRR EU) Excluding FF&U - Adjusted	$ 302,314	Sum Lines 3 thru 9	10
11				11
12	Gross Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	12
13				13
14	Annual Fix Charge Rate ($AFCR_{EU}$)	16.0051%	Line 10 / Line 12	14
15				15
16	Weighted Forecast Plant Additions	$ 2,166,500	Summary of HV-LV Plant Additions; Pg 1; Ln 6	16
17				17
18	Forecast Period Capital Addition Revenue Requirements	$ 346,750	Line 14 x Line 16	18
19				19
20	**B. Derivation of Revenue Requirements for Transmission Plant Held for**			20
21	**Future Use During the Forecast Period**			21
22	Forecast Period Transmission Plant Held for Future Use	$ -	Not Applicable in TO4-Cycle 1	22
23				23
24	Cost of Capital Rate $_{(COCR)}$	0.0000%	Not Applicable in TO4-Cycle 1	24
25				25
26	Revenue Requirements for Transmission Plant Held for Future Use	$ -	Line 22 x Line 24	26

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Forecast Period Capital Additions Revenue Requirements (FC $_{EU}$)
For the Forecast Period June 1, 2012 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
	ANNUAL FIXED CHARGES APPLICABLE TO INCENTIVE CAPITAL PROJECTS			
1	**A. Derivation of Annual Fix Charge Rate (AFCR $_{EU-IR-ROE}$) Applicable to**			1
2	**Incentive Weighted Forecast Plant Additions (ROE Incentive Only):**			2
3	PYRR $_{EU-IR-ROE}$ Excluding Franchise Fees and Uncollectible	$ 316,574	PYRR Incentive Work Paper	3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5	Valley Rainbow Project Cost Amortization Expense	(1,893)	Statement BK-1; Page 1; Line 12	5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7	Transmission Related Amortization of Investment Tax Credit	265	Statement BK-1; Page 1; Line 29	7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9	Total (PYRR $_{EU}$) Excluding FF&U - Adjusted	$ 312,613	Sum Lines 3 thru 8	9
10				10
11	Gross Electric Transmission Plant	$ 1,888,861	Statement BK-1; Page 3, Line 6	11
12				12
13	**Annual Fix Charge Rate (AFCR $_{EU-IR-ROE}$)**	**16.5503%**	**Line 9 / Line 11**	13
14				14
15	**Incentive Weighted Forecast Plant Additions**	**$ 100,000**	**HV-LV; FPAWP**	15
16				16
17	**Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-R}$**	**$ 16,550**	**Line 13 x Line 15**	17
18				18
19	**B. Derivation of Transmission CWIP Incentive Projects Revenue Requirements:**			19
20	**Transmission Construction Work In Progress Incentive Projects**	**$ 50,000**	**HV-LV; FPAWP**	20
21				21
22	**Cost of Capital Rate $_{(COCR)}$**	**11.8691%**	Statement AV; Page 14, Line 33	22
23				23
24	**Transmission CWIP Incentive Projects Revenue Requirements**	**$ 5,935**	**Line 20 x Line 22**	24

San Diego Gas & Electric Company
Statement BK-1
Derivation of End Use Base Transmission Revenue Requirements (BTRR $_{EU}$)
For the Rate Effective Period September 1, 2013 - August 31, 2014
($1,000)

Line No.		Amounts	Reference	Line No.
1	**A. End Use Customer Base Transmission Revenue Requirement (BTRR $_{EU}$):**			1
2				2
3	End of Prior Year Revenues (PYRR $_{EU}$) Excluding FF&U	$ 306,275	Statement BK-1; Page 1; Line 35	3
4				4
5	**Incentive End of Prior Year Revenues (PYRR $_{EU-IR}$) Excluding FF&U**	**43,465**	**Statement BK-1; Page 1; Line 46**	5
6				6
7	Sub-Total Base Period Revenues	$ 349,740	Sum Lines 3 thru 5	7
8			Not Applicable in TO4-Cycle 1, but Shown for	8
9	**True-Up Period Adjustment**	**$ (7,625)**	Illustrative Purposes Only. See Exh. SDG-6-2.	9
10			Not Applicable in TO4-Cycle 1, but Shown for	10
11	**Interest True-Up Adjustment**	**1,014**	Illustrative Purposes Only. See Exh. SDG-6-3.	11
12				12
13	Sub-Total True-Up Adjustments	$ (6,611)	Sum Lines 9 thru 11	13
14				14
15	**B. Annual Fixed Charges Applicable to Capital Projects:**			15
16				16
17	Forecast Period Capital Addition Revenue Requirements	$ 346,750	Statement BK-1; Page 4, Line 18	17
18				18
19	Revenue Requirements for Transmission Plant Held for Future Use	-	Statement BK-1; Page 4, Line 26	19
20				20
21	Sub-Total Revenue Requirements for Capital Projects	$ 346,750	Sum Lines 17 thru 19	21
22				22
23	**C. Annual Fixed Charges Applicable to Incentive Capital Projects:**			23
24				24
25	**Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-ROE}$)**	**$ 16,550**	**Statement BK-1; Page 5, Line 17**	25
26				26
27	**Transmission CWIP Incentive Projects Revenue Requirements**	**5,935**	**Statement BK-1; Page 5, Line 24**	27
28				28
29	Sub-Total Revenue Requirements for Incentive Capital Projects	$ 22,485	Sum Lines 25 thru 27	29
30				30
31	**D. Subtotal BTRR $_{EU}$ Excluding FF&U:**	$ 712,363	Sum Lines 7; 13; 21; 29	31
32				32
33	Transmission Related Municipal Franchise Fees Expenses	7,320	Line 31 x 1.0275%	33
34	Transmission Related Uncollectible Expense	1,004	Line 31 x 0.141%	34
35				35
36	**E. Total Retail BTRR $_{EU}$ With FF&U:**	$ 720,687	Sum Lines 31 thru 34	36

Exhibit - SDG-6-6

Illustrative Example of Prior Year Incentive Revenue Requirements Calculation – Incentive ROE Only

San Diego Gas & Electric Company
Statement BK-1 - Derivation of PYRR $_{EU}$ @ Incentive ROE of 12.30%
Incentive ROE Only - Workpaper
For the Base Period Ending - May 31, 2012
($1,000)

Exhibit No. SDG-6-6
Page 1 of 3

Line No.			Amounts	Reference	Line No.
1	**Prior Year Incentive Revenue Requirements: (PYRR$_{EU-IR-ROE}$)**				1
2	Transmission Operation & Maintenance Expense	$	48,715	Statement AH; Page 5, Line 8	2
3					3
4	Transmission Related A&G Expenses		42,317	Statement AH; Page 5, Line 57	4
5					5
6	CPUC Intervener Funding Expenses		-	Statement AH; Page 5, Line 9	6
7					7
8	Total O&M Expenses	$	91,032	Sum Lines 2; 4; 6	8
9					9
10	Transmission, Intangible, General and Common Depr. & Amort. Expense		54,756	Statement AJ; Page 7, Line 19	10
11					11
12	Valley Rainbow Project Cost Amortization Expense		1,893	Statement AJ; Page 7, Line 23	12
13					13
14	Transmission Abandoned Project Cost Amortization Expense		-	Statement AJ; Page 7, Line 25	14
15					15
16	Transmission Related Property Taxes Expense		12,282	Statement AK; Page 8, Line 27	16
17					17
18	Transmission Related Payroll Taxes Expense		2,030	Statement AK; Page 8, Line 34	18
19					19
20	Sub-Total Expense	$	161,993	Sum Lines 8; 10; 12; 14; 16; 18	20
21					21
22	**Incentive Cost of Capital Rate $_{(ICOCR)}$**		**12.7129%**	**Incentive ROEWP; Page 2, Line 33**	22
23					23
24	Non-Incentive Transmission Rate Base	$	1,220,533	Statement BK-1; Pg 2, Line 20	24
25					25
26	Return and Associated Income Taxes	$	155,165	Line 22 x Line 24	26
27					27
28	South Georgia Income Tax Adjustment		2,333	Statement AQ; Page 11, Line 1	28
29	Transmission Related Amortization of ITC		(265)	Statement AR; Page 12, Line 1	29
30	Transmission Related Amort of Excess Deferred Tax Liability		-	Statement AR; Page 12, Line 3	30
31	Transmission Related Revenue Credits		(2,652)	Statement AU; Page 13, Line 11	31
32	Transmission Related Regulatory Debits		-	Not Applicable in TO4 Cycle 1	32
33	(Gains)/Losses from Sale of Plant Held for Future Use		-	Statement AU; Page 13, Line 13	33
34					34
35	End of Prior Year Revenue (PYRR $_{EU-IR-ROE}$)	$	316,574	Line 20 + Sum of Lines (26 thru 33)	35

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV - Incentive ROE Workpaper @ 12.30%
Incentive - Cost of Capital and Fair Rate of Return
Base Period - May 31, 2012
($1,000)

Exhibit No. SDG-6-6
Page 2 of 3

Line No.					Amounts	Reference	Line No.
1	**Long-Term Debt Component - Denominator:**						1
2	(Plus) Bonds (Acct. 221) (p112.Line18c)				$ 3,536,905		2
3	(Less) Reacquired Bonds (Acct. 222) (p112.Line19c)				-		3
4	(Plus) Other Long-Term Debt (Acct. 224) (p112.Line21c)				253,720		4
5	(Plus) Unamortized Premium on Long-Term Debt (Acct 225) (p112.Line22c)				-		5
6	(Less) Unamortized Discount on Long-Term Debt-Debit (Acct 226) (p112.Line23c)				12,055		6
7	LTD = Long Term Debt (p112, sum of Line17d thru Line22d, details on p256-257)				$ 3,778,570	Line 2 Minus Line 3 Plus Lines 4 & 5 Minus Line 6	7
8							8
9	**Long-Term Debt Component - Numerator:**						9
10	(Plus) Interest on Long-Term Debt (427) (p117.Line62c)				$ 163,736		10
11	(Plus) Amort. of Debt Disc. and Expense (428) (p117.Line63c)				2,607		11
12	(Plus) Amortization of Loss on Reacquired Debt (428.1) (p117.Line64c)				3,388		12
13	(Less) Amort. of Premium on Debt-Credit (429) (p117.Line65c)				-		13
14	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1) (p117.Line66c)				-		14
15	i = LTD interest (p117, sum of Line56c thru Line60c, details on p257))				$ 169,731	Sum Lines 10; 11; 12 Minus Lines 13 & 14	15
16							16
17	**Cost of Long-Term Debt:**				4.49%	Line 15 / Line 7	17
18							18
19							19
20	**Preferred Equity Component:**						20
21	PF = Preferred Stock - Acct 204 (p112.3c)				$ 78,475		21
22	d(pf) = Total Dividends Declared-Preferred Stocks (Acct. 437) (p118.29c)				4,820		22
23	Cost of Preferred Equity				6.14%	Line 22 / Line 21	23
24							24
25							25
26	**Common Equity Component:**						26
27	Proprietary Capital (p112.16c)				$ 3,990,776		27
28	(Less) Preferred Stock - Acct 204 (p112.3c)				78,475		28
29	(Less) Unappropriated Undistributed Subsidiary Earnings (Acct. 216.1) (p112.12c)				-		29
30	CS = Common Stock				$ 3,912,301	Line 27 Minus Lines 28 & 29	30
31							31
32	**Incentive Return on Common Equity:**				12.30%	For Illustration Only	32
33		(a)	(b)	(c)	(d) = (b) x (c)		33
34			Cap. Struct.		Weighted		34
35	**Weighted Cost of Capital:**	Amount	Ratio	Cost of Capital	Cost of Capital		35
36							36
37	Long-Term Debt	$ 3,778,570	48.63%	4.49%	2.18%	TO4-Cycle 1 - Illustration Only	37
38	Preferred Equity	78,475	1.01%	6.14%	0.06%	TO4-Cycle 1 - Illustration Only	38
39	Common Equity	3,912,301	50.36%	12.30%	6.19%	TO4-Cycle 1 - Illustration Only	39
40	Total Capital	$ 7,769,346	100.00%		8.43%	Sum Lines 37; 38; 39	40
41							41
42							42
43	**Cost of Equity Component:**				6.25%	Sum Lines 38; 39	43

SAN DIEGO GAS AND ELECTRIC COMPANY
Statement AV - Incentive ROE Workpaper @ 12.30%
Incentive - Cost of Capital and Fair Rate of Return
Base Period - May 31, 2012
($1,000)

Exhibit No. SDG-6-6
Page 3 of 3

Line No.		Amounts	Reference	Line No.
1	**Derivation of Incentive Ratemaking Cost of Capital Rate:**			1
2				2
3	**a. Federal Income Tax Component:**			3
4				4
5	Where:			5
6	A = Sum of Preferred Stock and Return on Equity Component	6.25%	Statement AV WP; Page AV1; Line 43	6
7	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$ 265	Statement AR; Page 10; Line 5	7
8	C = Equity AFUDC Component of Transmission Depreciation Expense	$ -		8
9	D = Transmission Rate Base	$ 1,220,533	Statement BK1; Page 2; Line 20	9
10	FT = Federal Income Tax Rate July 1, 2012	35%	Federal Income Tax Rate	10
11				11
12	Federal Income Tax = (A + [(C - B) / D]) (FT) =	3.3537%	Federal Income Tax	12
13	1 - FT			13
14				14
15				15
16	**B. State Income Tax Component:**			16
17				17
18	Where:			18
19	A = Sum of Preferred Stock and Return on Equity Component	6.25%	Statement AV WP; Page AV1; Line 43	19
20	B = Trans. Related Amort. of ITC and Excess Deferred Tax Liab.	$ 265	Statement AR; Page 10; Line 5	20
21	C = Equity AFUDC Component of Transmission Depreciation Expense	$ -		21
22	D = Transmission Rate Base	$ 1,220,533	Statement BK1; Page 2; Line 20	22
23	FT = Federal Income Tax Rate July 1, 2012	3.3537%	Statement AV WP; Page AV2; Line 12	23
24	ST = State Income Tax Rate July 1, 2012	8.84%	State Income Tax Rate	24
25				25
26	State Income Tax = (A + [(C - B) / D] + Federal Income Tax) (ST) =	0.9292%	State Income Tax	26
27	1 - FT			27
28				28
29	**C. Total Federal & State Income Tax Rate:**	4.2829%	Line 12 + Line 26	29
30				30
31	**D. Total Weighted Cost of Capital After Federal & State Income Taxes:**	8.4300%	Stmnt AV WP; Page AV1; Line 40	31
32				32
33	**E. Cost of Capital Rate Before Federal & State Income Taxes:**	12.7129%	Sum Lines 29; 31	33

Exhibit - SDG-6-7

Illustrative Example of Wholesale Base Transmission Revenue Requirements Calculation & Bifurcation Between High Voltage and Low Voltage

San Diego Gas & Electric Company
Statement BK-2
Derivation of CAISO Total Base Transmission Revenue Requirements
For the Base Period Ending May 31, 2012
($1,000)

Exhibit No. SDG-6-7
Page 1 of 2

Line No.		Amounts	Reference	Line No.
1	**A. Total (PYRR $_{EU}$) Excluding FF&U [1]**	$ 349,740	Statement BK-1; Page 1; Line 48	1
2				2
3	**B. Wholesale BTRR Adjustments:**			3
4	CPUC Intervenor Funding Expense	-	Statement BK-1; Page 1; Line 6	4
5				5
6	South Georgia Income Tax Adjustment	(2,333)	Statement BK-1; Page 1; Line 28	6
7				7
8	Transmission Related Amortization of Excess Deferred Tax Liabilities	-	Statement BK-1; Page 1; Line 30	8
9				9
10	Total Wholesale BTRR Adjustments	$ (2,333)	Sum Lines 4 thru 8	10
11				11
12	Wholesale Prior Year Revenue Requirements (PYRR $_{ISO}$)	347,407	Sum Lines 1; 10	12
13				13
14	**True-Up Adjustment**	**(7,625)**	**Statement BK-1; Page 6; Line 9**	14
15				15
16	**Interest True-Up Adjustment**	**1,014**	**Statement BK-1; Page 6; Line 11**	16
17				17
18	Wholesale BTRR Before Forecast Prior Year Revenue Requirements (PYRR $_{ISO}$)	$ 340,796	Sum Lines 12 thru 16	18
19				19
20	Forecast Period Capital Addition Revenue Requirements	346,750	Statement BK-1; Page 4; Line 18	20
21				21
22	Forecast Period Revenue Requirements - Transmission Plant Held for Future Use	-	Statement BK-1; Page 4; Line 26	22
23				23
24	Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-ROE}$)	16,550	Statement BK-1; Page 5; Line 17	24
25				25
26	Forecast Transmission CWIP Incentive Projects Revenue Requirements	5,935	Statement BK-1; Page 5; Line 24	26
27				27
28	**C. Total Wholesale BTRR Excluding Franchise Fees**	$ 710,030	Sum Lines 18 thru 26	28

[1] Total Prior Year Revenues (PYRR) or Base Period Cost of Service is for 12 months ending May 31, 2012.

San Diego Gas & Electric Company
Statement BK-2
Derivation of CAISO HV Transmission Facility (BTRR $_{CAISO-HV}$) &
LV Transmission Facility (BTRR $_{CAISO-LV}$) Revenue Requirements
For the Rate Effective Period September 1, 2013 - August 31, 2014
($1,000)

Exhibit No. SDG-6-7
Page 2 of 2

Line No.		Total	Reference	Line No.
	A. Derivation of Revenues Related With Total Transmission Facilities:			
1	Wholesale BTRR Before Forecast Prior Year Revenue Requirements (PYRR $_{ISO}$)	$ 340,796	Statement BK-2; Page 1; Line 18	1
2				2
3	Forecast Period Capital Addition Revenue Requirements	346,750	Statement BK-2; Page 1; Line 20	3
4				4
5	Forecast Period Revenue Requirements - Transmission Plant Held for Future Use	-	Statement BK-2; Page 1; Line 22	5
6				6
7	Forecast Period Incentive Capital Additions Revenues (FC $_{EU-IR-ROE}$)	16,550	Statement BK-2; Page 1; Line 24	7
8				8
9	Forecast Transmission CWIP Incentive Projects Revenue Requirements	5,935	Statement BK-2; Page 1; Line 26	9
10				10
11	Total Wholesale BTRR Excluding Franchise Fees	$ 710,030	Sum Lines 1 thru 9	11
12				12

Line No.		(a) Total	(b) High Voltage	(c) Low Voltage	Reference	Line No.
13	**B. Derivation of Split Between HV and LV:** [1]					13
14	**1. Percent Split Between HV & LV for Recorded**					14
15	**Gross Transmission Plant Facilities:**				HV-LV Study	15
16	Gross Transmission Plant Facilities @ 5/31/2012	$ 1,844,046	$ 797,012	$ 1,047,034	Page 1; Cols. B and C	16
17	HV-LV Plant Allocation Ratios @ 5/31/2012	100.00%	43.22%	56.78%	Ratios Based on Line 16	17
18	Total HV-LV Transmission Plant Facilities Revenues @ 5/31/2012	$ 340,796	$ 147,295	$ 193,501	Line 17 x Line 18; Col A	18
19						19
20	**2. Percent Split Between HV and LV of Forecast**					20
21	**Plant Adds From 6/1/2012 - 8/31/2014:**	$ 2,166,500	$ 1,787,002	$ 379,498	Summary of Wtd HV-LV	21
22	HV-LV Plant Allocation Ratios Based on Forecast Plant Additions	100.00%	82.48%	17.52%	Plant Adds; Page 1; Line 11	22
23	Total HV-LV Transmission Forecast Plant Additions Revenues	$ 369,235	$ 304,557	$ 64,677	Line 22 x Line 23; Col A	23
24						24
25	**C. Summary of ISO Transmission Facilities by**					25
26	**High Voltage and Low Voltage Classification:**					26
27	Recorded Transmission Facilities (BTRR $_{ISO}$) Excluding Franchise Fees	$ 340,796	$ 147,295	$ 193,501	Line 18 From Above	27
28	Franchise Fee (FF) @ 1.0275% [2]	3,501	1,513	1,988	Line 27 x 1.0275%	28
29	Total Recorded Transmission Facilities BTRR $_{ISO}$ With Franchise Fees	$ 344,297	$ 148,808	$ 195,489	Sum Lines 27 thru 28	29
30						30
31	Forecast Transmission Facilities (BTRR $_{ISO}$) Excluding Franchise Fees	$ 369,235	$ 304,557	$ 64,677	Line 23 From Above	31
32	Franchise Fee (FF) @ 1.0275% [2]	3,794	3,129	665	Line 31 x 1.0275%	32
33	Total Recorded Transmission Facilities BTRR $_{ISO}$ With Franchise Fees	$ 373,029	$ 307,686	$ 65,342	Sum Lines 31 thru 32	33
34						34
35	**D. Total (BTRR $_{ISO}$) With Franchise Fees:** [3]	$ 717,325	$ 456,494	$ 260,831	Line 29 + Line 33	35

[1] Pursuant to the ISO's July 5, 2005 filing in compliance with the Commission's December 21, 2004 order, 109 FERC ¶ 61,301 (December 21, Order) and June 2, 2005 Order, 111 FERC ¶ 61,337 (June 2 Order), SDG&E in the instant filing has followed the ISO's new guidelines to separate all elements of its transmission facilities into HV and LV components. TRBAA cost components shown in the instant filing are separated into the HV and LV components applicable to the ISO's HV and LV guidelines in effect 1/1/2005 pursuant to ISO Tariff Appendix F, Sch.3, Section 8.1.

[2] Base franchise fees are applicable to all SDG&E customers.

[3] The following HV-LV Wholesale Base Transmission Revenue Requirements will be used by the CAISO to develop the TAC rates for the rate effective period September 1, 2013 through August 31, 2014.

Exhibit - SDG-6-8

Illustration – CAISO TAC Rate Input Form High Voltage Utility Specific Rate Retail; Low Voltage Wheeling Access Charge Rate; & Low Voltage Access Charge Rate

Exhibit No. SDG-6-8
Page 1 of 1

FOR ILLUSTRATIVE PURPOSES ONLY

SAN DIEGO GAS & ELECTRIC COMPANY
Rate Design Information - Wholesale Transmission Rates
CAISO TAC Rates Input Form - September 1, 2013 through August 31, 2014
High-Voltage Utility Specific Rates, Low -Voltage Wheeling Access Charge & Low Voltage Access Charge Rates

Line No.	Components	(1) High Voltage TRR	(2) Low Voltage TRR	(3) = (1) + (2) Combined TRR	Notes & Reference	Line No.
1	Wholesale Base Transmission Revenue Requirement [1]	$ 456,494,000	$ 260,831,000	$ 717,325,000	Statement BL Tab CAISO-Wholesale; Pg 2; Line 1	1
2						2
3	Wholesale TRBAA Forecast [2]	$ (1,799,875)	$ 40,487	$ (1,759,388)	Statement BL Tab CAISO-Wholesale; Pg 2; Line 16	3
4						4
5	Transmission Standby Revenues [3]	$ (6,007,435)	$ (3,432,521)	$ (9,439,956)	Statement BL Tab CAISO-Wholesale; Pg 2; Line 18	5
6						6
7	Wholesale Net Transmission Revenue Requirement	$ 448,686,690	$ 257,438,966	$ 706,125,656	Sum Lines 1; 3; 5	7
8						8
9	Gross Load - MWH	21,516,679	21,516,679	21,516,679	Statement BD; Page 1; Col. B; Line 14	9
10						10
11	Utility Specific Access Charges ($/MWH)	$ 20.8530	$ 11.9646	$ 32.8176	Line 7 / Line 9	11
12						12

NOTES:

1 Wholesale Base TRR comes from Exhibit No. SDG-6-7; Page 2 of 2; Line 35.

2 TRBAA information comes from Docket No. ER13-602-000, filed on December 20, 2012. The TRBAA will be in effect until 12/31/2013. The TBAA amount will change effective January 1, 2014, after SDG&E makes its annual TRBAA filing in December 2013

3 Standby Revenues come from Statement BG; Page 1, Line 9, Col. (A) of the instant TO4-Cycle 1 Informational Filing. The Total Standby Revenues is allocated based on the TO4-Cycle 1 HV-LV splits of wholesale BTRR.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

Raulin R. Farinas, being duly sworn, on oath, says that he is the Raulin R. Farinas identified in the foregoing prepared direct testimony; that he prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

Raulin R. Farinas

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 7th day of February, 2013 before me, Rosalinda Rossi, a Notary Public, personally appeared Raulin R. Farinas, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

ROSALINDA ROSSI
COMM. #1858772
NOTARY PUBLIC • CALIFORNIA
SAN DIEGO COUNTY
Commission Expires Jul 24, 2013

Rosalinda Rossi

Exhibit No. SDG-7

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
JOHN D. JENKINS
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

SAN DIEGO GAS & ELECTRIC COMPANY
EXHIBIT NO. SDG-7

#274922

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

San Diego Gas & Electric Company) Docket No. ER13-___-000

PREPARED DIRECT TESTIMONY OF
JOHN D. JENKINS
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

Q1. Please state your name and business address for the record.

A1. My name is John D. Jenkins, and my business address is 1010 Tavern Road, Alpine, CA 91901.

Q2. Briefly describe your current responsibilities at San Diego Gas and Electric Company (SDG&E or Company).

A2. I am responsible for the management of the Company's electric capital projects.

Q3. Briefly describe your professional background.

A3. I was hired by San Diego Gas & Electric in 1999 as an Associate Engineer, which is a title that I held for eighteen months. My next position was an Engineer II working at SDG&E's Metro Construction & Operations facility, which is a position that I held for two and a half years. I was then promoted to a Team Lead position in SDG&E's Distribution Operations Department and held that position for six months. My next position was an Operations & Engineering Manager at SDG&E's Northeast Construction & Operations facility, which is a position that I held for one year. I was then promoted to Electric Distribution Engineering Manager and held that position for two and a half years. My next position was the Substation Engineering & Design Manager, which is a position that I held for two and a half years. I then became the Substation Project Manager for the Sunrise Powerlink Project (Sunrise) for the next three years. I was then promoted to Manager of Construction & Operations for SDG&E's Beach Cities region for the next four months. Finally, in September 2012, I was promoted to Director – Major Projects and that is the position that I currently hold.

Q4. Briefly describe your educational background.

A4. I attended California Polytechnic State University, San Luis Obispo, graduating with a Bachelor of Science degree in Electrical Engineering. I am also a registered Professional Engineer in the state of California in the field of Electrical Engineering.

Q5. Have you previously testified before the Federal Energy Regulatory Commission (FERC or Commission)?

A5. No.

II. PURPOSE OF TESTIMONY

Q6. What is the purpose of your testimony?

A6. The purpose of my testimony is to sponsor the Forecast of Capital Additions (Forecasts) and related exhibits. I will describe transmission capital additions, processes involved in developing the forecast and describe the California Independent System Operator (CAISO) process which establishes the need for many of the projects included in the Forecast Period. I note that the processes and procedures SDG&E intends to use in the TO4 Formula to develop Forecasts are identical to those used in the TO3 Formula. My remaining testimony will cover the following items:

1. Overview
2. Types of Transmission Projects
3. CAISO Approval Process
4. High Voltage / Low Voltage Percentages
5. East County Substation Project

1. Overview

Q7. How do you determine what projects are included in the Forecast Period?

A7. Transmission projects with estimated in-service dates that fall within the Forecast Period are included in the transmission forecast.

Q8. What months are included in the Forecast Period?

A8. The Forecast Period of TO4-Cycle 1 consists of 27 months. The 27 month period commenced June 2012 and runs through August, 2014. Any projects estimated to go into service during these months are considered plant additions which are used and useful to customers during the Rate Effective Period, September 2013 through August 2014. For TO4-Cycle 2 and subsequent annual filings, called cycles, the Forecast Period will consist of 24 months beginning in January of year 1 and ending in December of year 2. (*e.g.*, the Forecast Period for Cycle 2 will run from January 2014 through December 2015).

Q9. What process do you follow to develop the list of projects included in the Forecast Period?

A9. The process of identifying which transmission projects to include in the Forecast Period involves reviewing various sources of information (*e.g.*, various regulatory reports, prior transmission cycle filings) to develop a preliminary list of potential projects. Using the preliminary list as the basis for additions, further meetings are held with the Transmission Planning, Transmission Engineering & Design, and Major Project groups to establish and validate a final estimated project in-service date.

Q10. How are the projects organized in this Forecast?

A10. Projects of a similar nature are grouped under specific categories. Exhibit No. SDG-7-1, Forecast Capital Addition Worksheet, shows the various categories of projects included in TO4 Cycle 1 as Blanket Projects, Transmission Line Projects, Substation Projects, Wood to Steel Pole Replacement Projects, Network Upgrade to Accommodate Generator Interconnection Projects and Sunrise. A brief description of categories and examples of work performed under each is provided in the Types of Projects portion of this testimony.

Q11. What exhibits are included to support forecast capital additions?

A11. Included in the filing are the following exhibits:

- Exhibit No. SDG-7-1- Forecast of Capital Additions
  - Lists all projects included in the forecast identifying in service date, estimated cost and what percentage of the project is estimated to be high and low voltage.
- Exhibit No. SDG-7-2- CAISO Approval Exhibit
  - Identifies whether a project was approved by the CAISO and references the CAISO Transmission Plan where approval was granted.
- Exhibit No. SDG-7-3- CPUC Licensing Exhibit
  - Identifies the status or anticipated status of a project's CPUC licensing requirements.

- Exhibit No. SDG-7-4- Large Project Report
  - Lists and summarizes details for any project whose cost exceeds $5 million. It lists project name, project cost, weighted project cost, in service date, whether or not the project was approved by the CAISO, the CPUC licensing status and what benefit this project provides to customers.

Q12. Are all projects included in the Forecast Period approved by the CAISO?

A12. No. Many, but not all projects included in the Forecast Period are approved by the CAISO. Some projects are required to meet the North American Electric Reliability Corporation (NERC) reliability criteria or for other operational reasons are identified and approved independently of the CAISO process. Some examples of non – CAISO approved projects include transmission compliance work performed under a blanket project, transmission line work to replace aging infrastructure, substation enhancements and wood to steel pole replacements in high fire risk areas.

Q13. How does SDG&E develop cost estimates for the projects included in the Forecast Period?

A13. The general process involves gathering project costs to date plus estimated future monthly cash flows from the project manager. SDG&E then calculates an Allowance for Funds Used during Construction (AFUDC) on the monthly cash flows up and until the project is placed in service.

2. Types of Projects

Q14. In Section 1 above, you mentioned that projects are categorized as Blanket Projects, Transmission Line Projects, Substation Projects, Wood to Steel Pole Replacement Projects, Network Upgrade to Accommodate Generator Interconnection Projects. Please explain each of these categories.

A14. Blanket Projects

- Blanket projects are created to cover capital projects that do not fall within a specific category. Typically, the projects covered by a Blanket budgets are small in nature and fall within a specific type of work, or category. Blanket budgets differ from project-specific budgets in that there is a general scope of work that covers the types of work captured under the Blanket projects. In some cases, Blanket projects are established to cover a multi-year program. The significant or higher cost Blanket projects included in TO4-Cycle 1 are:

- Electric Transmission Line Reliability
  - Work includes restoration of degraded transmission facilities, a wood pole restoration program, repairs of the system in the event of a disaster and installation of aerial markers on transmission lines in accordance with Federal Aviation Administration requirements.
- Transmission Infrastructure Improvements
  - Work includes proactive reliability improvements and replacement of aging and obsolete substation equipment such as transformers, transformer bushings, oil circuit breakers, disconnects, capacitors, transmission line relaying, and seismic hardening as identified by SDG&E internal review teams.
- Substation Security
  - Involves installation or replacement of substation security systems to comply with NERC guidelines to protect critical infrastructure facilities and to reduce or deter vandalism that could result in system outages or personal injury.

- **Transmission Line Projects**
- These cover a wide range of projects needed for improved system reliability consistent with NERC reliability and operating criteria, including but not limited to those approved and required by the CAISO. The scope of work can range from a new transmission line to reconductored transmission circuits to replacement of aging underground cable.
- **Substation Projects**
- In addition to projects identified *via* transmission planning and approved by the CAISO which are required for load growth and compliance with planning and operating criteria (*e.g.*, addition of a transformer bank), substation projects may include substation rebuilds to address reliability concerns, installation of additional reactive capacity, purchase of emergency equipment to reduce the duration of outages and facilitate repairs and replacement of overstressed circuit breakers.

- **Wood to Steel Pole Replacement Projects**
    - These projects improve the reliability of transmission lines in high fire risk and wind prone areas by replacing by wood poles with steel poles. These projects may also include replacing the existing conductor where necessary.
- **Network Upgrades to Accommodate Generator Interconnections**
    - These projects represent network upgrades needed to ensure the transmission system will perform in accordance with NERC, Western Electricity Coordinating Council (WECC), and CAISO reliability criteria once generators interconnect. The majority of recent activity in this category involves network upgrades required to accommodate renewable generation as entities strive to meet California Renewables Portfolio Standard (RPS) goals.

3. CAISO Transmission Planning Approval Process

Q15. Which projects included in the TO4-Cycle 1 forecast are approved by the CAISO?

A15. Please refer to Exhibit SDG7-2, column 4 to identify which projects were approved by the CAISO. Column 5 of the exhibit references the CAISO Board-approved transmission expansion plan and page number where approval is listed.

Q16. Please describe the CAISO's TPP as it relates to SDG&E projects, excluding Network Upgrades to Accommodate Generator Interconnections

A16. SDG&E is a Participating Transmission Owner (PTO) of the CAISO and is governed by the CAISO's FERC tariff and BPM. The BPM describes the CAISO's annual transmission planning process (TPP), which is the means by which projects necessary to meet NERC, WECC, and CAISO transmission reliability criteria are identified, proposed, and approved. This process runs approximately 18 months (from February to October of the following year) and is an open stakeholder process involving all CAISO PTOs and other entities such as the CPUC, California Energy Commission and independent generation and transmission developers.

Projects that are not required to meet reliability criteria but have economic or public policy benefits may also be identified by the CAISO or PTOs, with the difference that these projects, if approved by the CAISO, may be subject to a competitive bidding process among independent transmission developers.

Q17. Please briefly describe the CAISO's TPP as it relates to SDG&E to Network Upgrades to Accommodate Generator Interconnections

A17. Generator Interconnections to SDG&E-owned transmission facilities are governed by the CAISO's FERC approved tariff and guided by the CAISO's Generation Interconnection BPM. The BPM provides assistance in understanding and applying the tariff. Please refer to the applicable tariff provisions governing generator interconnections that are contained in Appendix Y (the Generation Interconnection Process) and Appendix DD (the Generation Interconnection and Deliverability Transmission Allocation Procedures). The CAISO tariff provides the process that generation projects proposing to interconnect to the CAISO grid are required to follow.

4. High Voltage and Low Voltage Splits

Q18. How does SDG&E determine the percentage of a project that is considered High Voltage (HV) and Low Voltage (LV)?

A18. The distinction between high and low voltage occurs at 200kV. Voltages in excess of 200kV are considered High Voltage, while 200kV or less are considered Low Voltage The common transmission voltage levels in the SDG&E system are 69kV, 138kV, 230kV and 500kV. Therefore, any 69kV and 138kV additions are considered LV work and any 230kV and 500kV work is considered HV. There are some projects that include both HV and LV. For these projects, analysis is performed to determine the breakdown between HV and LV.

5. East County Substation- ECO

Q19. Please describe the ECO project

A19. ECO includes the following major components:

- Construction of a 500/230/138 kV substation in southeastern San Diego County
- Construction of the 500 kV loop-in of the existing Southwest Power Link (SWPL), a short loop-in of the existing transmission line to the proposed ECO Substation
- Construction of a 138 kV transmission line, approximately 13.3 miles in length, running between the proposed ECO Substation and the rebuilt Boulevard Substation
- Rebuild of the existing Boulevard Substation.

ECO will be located on private lands owned by SDG&E or within SDG&E easements within unincorporated areas of San Diego County. The 13.3-mile, 138 kV transmission line will primarily be located on private lands within unincorporated San Diego County with a 1.5-mile portion located on Bureau of Land Management (BLM)-administered land.

Q20. Briefly describe the why the ECO project is necessary and describe the benefits it provides to rate payers.

A20. The proposed ECO Substation Project will provide an interconnection hub for renewable generation along SDG&E's existing Southwest Powerlink (SWPL) 500-kilovolt (kV) transmission line. In addition to accommodating the region's planned renewable generation, the project will also provide a second source for the southeastern 69 kV transmission system that avoids the vulnerability of common structure outages, which would increase the reliability of electrical service for Boulevard, Jacumba, and surrounding communities. The second source provided by the ECO project will allow for faster restoration during forced outages, and will greatly reduce the impacts of scheduled maintenance outages.

The proposed project will provide interconnection capability at three voltage levels (500, 230, and 138 kV), which will provide renewable generators the option to connect at a voltage level that is appropriately sized for their project. Without the flexibility for interconnection that the ECO project provides, integrating renewable generation projects would be much more costly for SDG&E ratepayers. The ability to connect at a voltage level commensurate with output allows for the economic sizing and location of generator projects, gen-tie transmission, and substation facilities associated with the interconnection of renewables. For instance, the presence of 138kV facilities provides interconnection capacity for small and medium size projects that are not economical to connect at higher voltages. Conversely, large scale projects can connect at 230kV or 500kV, taking advantage of the economies of scale not available to the smaller projects, since 230kV and 500kV facilities are much more expensive in comparison to 138kV. This flexible, multi-voltage interconnection hub allows for the harvesting of renewable resources that may be confined to small geographic locations, such as a small size wind generation plant located along a single, wind-optimum ridgeline, and not just the large, industrial-scale operations on the order of hundreds of megawatts. This approach ensures that ratepayer investment in renewable energy is commensurate with the level of new generation, and that SDG&E ratepayers aren't subsidizing small developers through the construction of several far flung substations, each catering to an individual generation project. Not only would this approach be highly inefficient, but would be short sighted as well. The ECO project provides an intelligent, well thought out long-term solution for incorporating renewable energy in a cost-effective and cohesive manner.

Q21. Does this conclude your testimony?

A21. Yes, it does.

Exhibit - SDG-7-1

Forecast of Transmission Capital Additions

SAN DIEGO GAS & ELECTRIC COMPANY

FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Voltage	Budget Code	In-Service Dates	2012 Plant Additions							Line No.
					Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	
1	**BLANKET BUDGET PROJECTS**											1
2	Electric Transmission Line Reliability Projects		100	9-mo. Avg. W/O Life	3,723	1,390	1,219	1,358	1,001	1,001	1,001	2
3	Transmission Substation Reliability		103	12-mo. Avg.W/O Life					317	293	270	3
4	Renewal of Transmission Line Easements		104	Various				20				4
5	Transmission Infrastructure Improvements		1145	18-mo. Avg.W/O Life	15	547	32	(14)				5
6	Electric Transmission System Automation		3171	12-mo. Avg.W/O Life					201	189	177	6
7	Fiber Optic for Relay Protection & Telecommunication		7144	Various								7
8	Substation Security		8162	18-mo. Avg.W/O Life					471	465	459	8
9	Condition Based Maintenance		9144	Aug-13, Apr-14								9
10	Synchronized Phasor Measurement		10138	Various								10
11	Dynamic Line Ratings		11147	Various								11
12	Automated Fault Location		12129	Dec-13								12
13	Composite Core Conductor		12130	Various								13
14	ARC Detection		12131	Various								14
15	SCADA Expansion		12132	Various								15
16	Transmission Ceramic Insulator Replacement		99128	Dec-13								16
17												17
18	**TRANSMISSION LINE PROJECTS**											18
19	13835 Tap at Talega	138kV	8158	Jun-Aug 12	1,068	1	(12)					19
20	Transmission ROW Palos Verdes - North Gila	500kV	12133	Jun-12	2,961							20
21	TL6927 EastGate-Rose Canyon	69kV	9151	Aug-12			551					21
22	On Ramp Aerial Lighting	230kV	11144	Aug-12, Jan-13, Mar-13			234					22
23	TL626 Reconductor	69kV	11148	Sep-12, Dec12				4,918			298	23
24	TL629C- Reconductor	69kV	12135	Sep-12, Dec-12				3,341			500	24
25	Ramona Transmission Reliability	69kV	10140	Apr-13								25
26	Laguna Niguel- TL 13835 & TL 13837 Underground Conversion	138kV	11142	Apr-13								26
27	New Escondido - Ash#2	69kV	9160	Jul-13								27
28	Replace TL617 Direct Buried Cable	69kV	11143	Jul-13								28
29	TL6913 Poway - Pomerado	69kV	9138	Jul-13, Jan-14								29
30	TL13821- Fanita Junction	138kV	9166	Apr-14								30
31	Reconductor TL631 El Cajon - Los Coches	69kV	12154	Jul-14								31
32	TL613 (Old Town-PB) Cable Replacement	69kV	12126	Jul-14								32
33												33
34	**SUBSTATION PROJECTS**											34
35	Miguel Bank 60	138kV	6133	Jul-12, Dec-12		(62)					1,464	35
36	69kV Capacitor Additions	69kV	9168	Various				428				36
37	Sweetwater Substation Rebuild	69kV	10125	Dec-12							562	37
38	69 /138kV Breaker Upgrades	69 / 138kV	9170	Jan-13, Jan-14								38
39	Emergency Equipment	69 /138 kV	6254	Various								39
40	Ocean Ranch (ET) Land Purchase	69 kV	5253	Jan-13								40
41	Telegraph Canyon- add 4th Bank	138kV	7245	Jan-13								41
42	Penasquitos add 230kV Capacitor Bank	230kV	12134	Jul-13								42
43	PICO Loop-in	138kV	12127	Jul-13								43
44	Sycamore Add 69kv Reactors	69kV	12157	Oct-13								44
45	Basilone Substation	69kV	11257	Jan-14								45
46	Los Coches Bank 50 / 51	69 / 138kV	10135	Apr-14								46
47												47

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Budget Code	2013 Plant Additions												Line No.
			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	
1	**BLANKET BUDGET PROJECTS**														1
2	Electric Transmission Line Reliability Projects	100	1,200	1,201	1,200	1,201	1,200	1,201	1,000	1,000	1,000	1,000	1,000	1,000	2
3	Transmission Substation Reliability	103	254	238	228	219	211	203	195	189	183	177	172	159	3
4	Renewal of Transmission Line Easements	104	50			50			50			50			4
5	Transmission Infrastructure Improvements	1145	7,001	643	617	593	580	568	568	568	568	568	551	530	5
6	Electric Transmission System Automation	3171	172	167	162	158	154	151	148	145	142	139	133	127	6
7	Fiber Optic for Relay Protection & Telecommunication	7144	149		149			1,041		446		669		2,379	7
8	Substation Security	8162	447	436	426	416	407	398	384	376	369	357	345	332	8
9	Condition Based Maintenance	9144								850					9
10	Synchronized Phasor Measurement	10138	405			405			405			405			10
11	Dynamic Line Ratings	11147	246			246			246			246			11
12	Automated Fault Location	12129												438	12
13	Composite Core Conductor	12130	1,048						1,048						13
14	ARC Detection	12131	74			74			74			74			14
15	SCADA Expansion	12132	197	197	197	197	197	197	197	197	197	197	197	197	15
16	Transmission Ceramic Insulator Replacement	99128												2,595	16
17															17
18	**TRANSMISSION LINE PROJECTS**														18
19	13835 Tap at Talega	8158													19
20	Transmission ROW Palos Verdes - North Gila	12133													20
21	TL6927 EastGate-Rose Canyon	9151													21
22	On Ramp Aerial Lighting	11144	939		69										22
23	TL626 Reconductor	11148													23
24	TL629C- Reconductor	12135													24
25	Ramona Transmission Reliability	10140				6,784									25
26	Laguna Niguel- TL 13835 & TL 13837 Underground Conversion	11142				12,402									26
27	New Escondido - Ash#2	9160							18,427						27
28	Replace TL617 Direct Buried Cable	11143							10,995						28
29	TL6913 Poway - Pomerado	9138							3,244						29
30	TL13821- Fanita Junction	9166													30
31	Reconductor TL631 El Cajon - Los Coches	12154													31
32	TL613 (Old Town-PB) Cable Replacement	12126													32
33															33
34	**SUBSTATION PROJECTS**														34
35	Miguel Bank 60	6133													35
36	69kV Capacitor Additions	9168	1,501						2,500			2,500			36
37	Sweetwater Substation Rebuild	10125													37
38	69 /138kV Breaker Upgrades	9170	3,051												38
39	Emergency Equipment	6254				3,000	1,000								39
40	Ocean Ranch (ET) Land Purchase	5253	2,500												40
41	Telegraph Canyon- add 4th Bank	7245	661												41
42	Penasquitos add 230kV Capacitor Bank	12134							3,745						42
43	PICO Loop-in	12127							2,107						43
44	Sycamore Add 69kv Reactors	12157										3,438			44
45	Basilone Substation	11257													45
46	Los Coches Bank 50 / 51	10135													46
47															47

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Budget Code	2014 Plant Additions								Total Plant Additions	High Voltage	Low Voltage	Line No.
			Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14				
1	**BLANKET BUDGET PROJECTS**													1
2	Electric Transmission Line Reliability Projects	100	1,200	1,201	1,200	1,201	1,200	1,201	1,200	1,201	$ 33,496	20%	80%	2
3	Transmission Substation Reliability	103	151	144	141	138	136	134	132	130	$ 4,414	9%	91%	3
4	Renewal of Transmission Line Easements	104	100			100			100		$ 520	0%	100%	4
5	Transmission Infrastructure Improvements	1145	510	490	472	454	437	421	406	392	$ 17,519	27%	73%	5
6	Electric Transmission System Automation	3171	125	124	123	122	121	120	119	118	$ 3,334	23%	77%	6
7	Fiber Optic for Relay Protection & Telecommunication	7144			1,784						$ 6,617	2%	98%	7
8	Substation Security	8162	322	311	302	292	284	275	267	260	$ 8,401	8%	92%	8
9	Condition Based Maintenance	9144				898					$ 1,748	18%	82%	9
10	Synchronized Phasor Measurement	10138	405			405			405		$ 2,835	80%	20%	10
11	Dynamic Line Ratings	11147	246			246			246		$ 1,722	25%	75%	11
12	Automated Fault Location	12129									$ 438	0%	100%	12
13	Composite Core Conductor	12130	1,048						1,048		$ 4,192	0%	100%	13
14	ARC Detection	12131	74			74			74		$ 518	0%	100%	14
15	SCADA Expansion	12132	197	197	197	197	197	197	197	197	$ 3,940	0%	100%	15
16	Transmission Ceramic Insulator Replacement	99128									$ 2,595	100%	0%	16
17											**$ 92,289**	**SUBTOTAL**		17
18	**TRANSMISSION LINE PROJECTS**													18
19	13835 Tap at Talega	8158									$ 1,057	0%	100%	19
20	Transmission ROW Palos Verdes - North Gila	12133									$ 2,961	100%	0%	20
21	TL6927 EastGate-Rose Canyon	9151									$ 551	0%	100%	21
22	On Ramp Aerial Lighting	11144									$ 1,241	100%	0%	22
23	TL626 Reconductor	11148									$ 5,216	0%	100%	23
24	TL629C- Reconductor	12135									$ 3,841	0%	100%	24
25	Ramona Transmission Reliability	10140									$ 6,784	0%	100%	25
26	Laguna Niguel- TL 13835 & TL 13837 Underground Conversion	11142									$ 12,402	0%	100%	26
27	New Escondido - Ash#2	9160									$ 18,427	0%	100%	27
28	Replace TL617 Direct Buried Cable	11143									$ 10,995	0%	100%	28
29	TL6913 Poway - Pomerado	9138	610								$ 3,854	0%	100%	29
30	TL13821- Fanita Junction	9166				29,917					$ 29,917	0%	100%	30
31	Reconductor TL631 El Cajon - Los Coches	12154							12,477		$ 12,477	0%	100%	31
32	TL613 (Old Town-PB) Cable Replacement	12126							10,903		$ 10,903	0%	100%	32
33											**$ 120,626**	**SUBTOTAL**		33
34	**SUBSTATION PROJECTS**													34
35	Miguel Bank 60	6133									$ 1,402	0%	100%	35
36	69kV Capacitor Additions	9168									$ 6,929	0%	100%	36
37	Sweetwater Substation Rebuild	10125									$ 562	0%	100%	37
38	69 /138kV Breaker Upgrades	9170	3,998								$ 7,049	0%	100%	38
39	Emergency Equipment	6254	2,900					300			$ 7,200	0%	100%	39
40	Ocean Ranch (ET) Land Purchase	5253									$ 2,500	0%	100%	40
41	Telegraph Canyon- add 4th Bank	7245									$ 661	0%	100%	41
42	Penasquitos add 230kV Capacitor Bank	12134									$ 3,745	100%	0%	42
43	PICO Loop-in	12127									$ 2,107	0%	100%	43
44	Sycamore Add 69kv Reactors	12157									$ 3,438	0%	100%	44
45	Basilone Substation	11257	925								$ 925	0%	100%	45
46	Los Coches Bank 50 / 51	10135				7,115					$ 7,115	0%	100%	46
47											**$ 43,633**	**SUBTOTAL**		47

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Voltage	Budget Code	In-Service Dates	2012 Plant Additions							Line No.
					Jun-12	Jul-12	Aug-12	Sep-12	Oct-12	Nov-12	Dec-12	
48	**WOOD TO STEEL PROJECTS**											48
49	TL616 Wood to Steel Pole Replacement	69kV	9135	Jun-12 ,Sep-12	8,955			745				49
50	TL13804 Wood to Steel Pole Replacement	138kV	11138	Feb-13								50
51	TL 13812 (DOD- Camp Pendleton) Wood to Steel	138kV	10150	Jul-13								51
52	TL 690C (DOD- Camp Pendleton) Wood to Steel	69kV	8257	Oct-13								52
53	TL6914 Wood to Steel Pole Replacement	69kV	9136	Dec-13								53
54	TL 6912 (DOD- Camp Pendleton) Wood to Steel Pole	69kV	10149	Jan-14								54
55	Miguel Getaways- TL 628 & TL643 Wood to Steel	69kV	12147	Jan-14								55
56	TL 6910 Wood to Steel Pole Replacement	69kV	9134	Jan-14								56
57	TL649 Wood to Steel Pole Replacement	69kV	9137	Apr-14								57
58	TL 13825 Wood to Steel Pole Replacement	138kV	11156	Apr-14								58
59	TL 664 Wood to Steel Pole Replacement	69kV	11133	Apr-14								59
60	TL 6926 Wood to Steel Pole Replacement	69kV	9132	Aug-14								60
61												61
62	**NETWORK UPGRADES TO ACCOMMODATE GENERATOR INTERCONNECTIONS**											62
63	Q493- Ocotillo Express	500kV	11146	Dec-12,Feb-13,Jun-13							20,000	63
64	Q337- Borrego Solar	69kV	10134	Jan-13								64
65	I.V. Bank 82	230 / 500kV	8163	Apr-13								65
66	Desert Star Transmission	230kV	10032	Jun-13								66
67	Q590- Campo Verde	230kV	12142	Jan-14								67
68	Q124-IV Solar-AES, Q510- I.V South, Q442-Centinela	230kV	8163 11149 11150	Jan-14								68
69	ECO- East County Substation	138/230/500 kV	7139	May-14								69
70	Q468-Agua Caliente	500kV	10142	Jun-14								70
71												71
72	**SUNRISE POWERLINK PROJECT:**											72
73	Sunrise Actuals	69/ 138/ 230 / 500 kV	4138	Jun-12 - Sep-12	1,618,360	(61,247)	(5,336)	4,085				73
74	Sunrise Forecast	69/ 138/ 230 / 500 kV	4138	Oct 12 - Jun 13					(18,395)	2,000	10,000	74
75												75
76				**Grand Total:**	**$1,635,082**	**($59,371)**	**($3,312)**	**$14,881**	**($16,405)**	**$3,948**	**$34,730**	76
77				**High Voltage:**	1,605,886	(60,209)	(4,796)	4,312	(17,899)	2,287	30,202	77
78				**Low Voltage:**	29,196	838	1,484	10,569	1,494	1,661	4,528	78
79				**Total:**	$ 1,635,082	$ (59,371)	$ (3,312)	$ 14,881	$ (16,405)	$ 3,948	$ 34,730	79
80				***Weighted***								80
81				***High Voltage***	$ 1,605,886	$ (60,209)	$ (4,796)	$ 4,312	$ (17,899)	$ 2,287	$ 30,202	81
82				***Low Voltage***	$ 29,196	$ 838	$ 1,484	$ 10,569	$ 1,494	$ 1,661	$ 4,528	82
83				***Total***	$ 1,635,082	$ (59,371)	$ (3,312)	$ 14,881	$ (16,405)	$ 3,948	$ 34,730	83

SAN DIEGO GAS & ELECTRIC COMPANY

FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Budget Code	2013 Plant Additions												Line No.
			Jan-13	Feb-13	Mar-13	Apr-13	May-13	Jun-13	Jul-13	Aug-13	Sep-13	Oct-13	Nov-13	Dec-13	
48	**WOOD TO STEEL PROJECTS**														48
49	TL616 Wood to Steel Pole Replacement	9135													49
50	TL13804 Wood to Steel Pole Replacement	11138		14,091											50
51	TL 13812 (DOD- Camp Pendleton) Wood to Steel	10150							2,291						51
52	TL 690C (DOD- Camp Pendleton) Wood to Steel	8257										3,043			52
53	TL6914 Wood to Steel Pole Replacement	9136												27,200	53
54	TL 6912 (DOD- Camp Pendleton) Wood to Steel Pole	10149													54
55	Miguel Getaways- TL 628 & TL643 Wood to Steel	12147													55
56	TL 6910 Wood to Steel Pole Replacement	9134													56
57	TL649 Wood to Steel Pole Replacement	9137													57
58	TL 13825 Wood to Steel Pole Replacement	11156													58
59	TL 664 Wood to Steel Pole Replacement	11133													59
60	TL 6926 Wood to Steel Pole Replacement	9132													60
61															61
62	**NETWORK UPGRADES TO ACCOMMODATE GENERATOR INTERCONNECTIONS**														62
63	Q493- Ocotillo Express	11146		2,000				18,000							63
64	Q337- Borrego Solar	10134	7,979												64
65	I.V. Bank 82	8163				13,074									65
66	Desert Star Transmission	10032						26,528							66
67	Q590- Campo Verde	12142													67
68	Q124-IV Solar-AES, Q510- IV South, Q442-Centinela	8163 11149 11150													68
69	ECO- East County Substation	7139													69
70	Q468-Agua Caliente	10142													70
71															71
72	**SUNRISE POWERLINK PROJECT:**														72
73	Sunrise Actuals	4138													73
74	Sunrise Forecast	4138	4,134	400		11,350		50,276							74
75															75
76		**Grand Total:**	**$32,007**	**$19,373**	**$3,049**	**$50,169**	**$3,749**	**$98,563**	**$47,624**	**$3,771**	**$2,459**	**$12,863**	**$2,397**	**$34,957**	76
77		**High Voltage:**	7,648	2,905	570	25,185	484	94,800	4,566	596	432	829	422	3,056	77
78		**Low Voltage:**	24,359	16,468	2,479	24,984	3,265	3,763	43,058	3,175	2,027	12,034	1,975	31,901	78
79		**Total:**	$ 32,007	$ 19,373	$ 3,049	$ 50,169	$ 3,749	$ 98,563	$ 47,624	$ 3,771	$ 2,459	$ 12,863	$ 2,397	$ 34,957	79
80		***Weighted***													80
81		***High Voltage***	$ 7,648	$ 2,905	$ 570	$ 25,185	$ 484	$ 94,800	$ 4,566	$ 596	$ 432	$ 760	$ 352	$ 2,292	81
82		***Low Voltage***	$ 24,359	$ 16,468	$ 2,479	$ 24,984	$ 3,265	$ 3,763	$ 43,058	$ 3,175	$ 2,027	$ 11,031	$ 1,646	$ 23,926	82
83		***Total***	$ 32,007	$ 19,373	$ 3,049	$ 50,169	$ 3,749	$ 98,563	$ 47,624	$ 3,771	$ 2,459	$ 11,791	$ 1,998	$ 26,218	83

SAN DIEGO GAS & ELECTRIC COMPANY

FORECAST OF TRANSMISSION CAPITAL ADDITIONS- TO4 CYCLE 1

Line No.	Project Name	Budget Code	2014 Plant Additions Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Total Plant Additions	High Voltage	Low Voltage	Line No.
48	**WOOD TO STEEL PROJECTS**													48
49	TL616 Wood to Steel Pole Replacement	9135									$ 9,700	0%	100%	49
50	TL13804 Wood to Steel Pole Replacement	11138									$ 14,091	0%	100%	50
51	TL 13812 (DOD- Camp Pendleton) Wood to Steel	10150									$ 2,291	0%	100%	51
52	TL 690C (DOD- Camp Pendleton) Wood to Steel	8257									$ 3,043	0%	100%	52
53	TL6914 Wood to Steel Pole Replacement	9136									$ 27,200	0%	100%	53
54	TL 6912 (DOD- Camp Pendleton) Wood to Steel Pole	10149	12,237								$ 12,237	0%	100%	54
55	Miguel Getaways- TL 628 & TL643 Wood to Steel	12147	1,800								$ 1,800	0%	100%	55
56	TL 6910 Wood to Steel Pole Replacement	9134	9,712								$ 9,712	0%	100%	56
57	TL649 Wood to Steel Pole Replacement	9137				11,341					$ 11,341	0%	100%	57
58	TL 13825 Wood to Steel Pole Replacement	11156				8,432					$ 8,432	0%	100%	58
59	TL 664 Wood to Steel Pole Replacement	11133				1,500					$ 1,500	0%	100%	59
60	TL 6926 Wood to Steel Pole Replacement	9132								15,345	$ 15,345	0%	100%	60
61											**$ 116,692**	**SUBTOTAL**		61
62	**NETWORK UPGRADES TO ACCOMMODATE GENERATOR INTERCONNECTIONS**													62
63	Q493- Ocotillo Express	11146									$ 40,000	100%	0%	63
64	Q337- Borrego Solar	10134									$ 7,979	0%	100%	64
65	I.V. Bank 82	8163									$ 13,074	100%	0%	65
66	Desert Star Transmission	10032									$ 26,528	100%	0%	66
67	Q590- Campo Verde	12142	2,374								$ 2,374	100%	0%	67
68	Q124-IV Solar-AES, Q510- I.V South, Q442-Centinela	8163 11149 11150	9,025								$ 9,025	100%	0%	68
69	ECO- East County Substation	7139					406,475	79	79	79	$ 406,712	38%	62%	69
70	Q468-Agua Caliente	10142						18,776			$ 18,776	100%	0%	70
71											**$ 524,468**	**SUBTOTAL**		71
72	**SUNRISE POWERLINK PROJECT:**													72
73	Sunrise Actuals	4138									$ 1,555,862	99%	1%	73
74	Sunrise Forecast	4138									$ 59,765	99%	1%	74
75											**$ 1,615,627**	**SUBTOTAL**		75
76		**Grand Total:**	**$47,958**	**$2,467**	**$4,218**	**$62,432**	**$408,850**	**$21,503**	**$27,653**	**$17,721**	**$ 2,513,335**	**Gross**		76
77		**High Voltage:**	12,230	439	468	974	154,881	19,221	826	436	$ 1,890,751	**HV**		77
78		**Low Voltage:**	35,728	2,028	3,750	61,458	253,969	2,282	26,827	17,285	$ 622,584	**LV**		78
79		**Total:**	$ 47,958	$ 2,467	$ 4,218	$ 62,432	$ 408,850	$ 21,503	$ 27,653	$ 17,721	**$ 2,513,335**	**Total**		79
80		***Weighted***										***Weighted***		80
81		***High Voltage***	$ 8,154	$ 256	$ 234	$ 406	$ 51,626	$ 4,805	$ 138	$ 36	$ 1,766,028	***HV***		81
82		***Low Voltage***	$ 23,818	$ 1,183	$ 1,875	$ 25,608	$ 84,655	$ 571	$ 4,471	$ 1,441	$ 353,572	***LV***		82
83		***Total***	$ 31,972	$ 1,439	$ 2,109	$ 26,014	$ 136,281	$ 5,376	$ 4,609	$ 1,477	$ 2,119,600	***Total***		83

Exhibit - SDG-7-2

CAISO Approval

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS - TO4 CYCLE 1

	1	2	3	4	5	
Line No.	Project Name	Voltage	Budget Code	ISO Approval Status	Unless otherwise noted, page reference pertains to the 2011 - 2012 CA ISO Transmission Plan	Line No.
1	**BLANKET BUDGET PROJECTS:**					1
2	Electric Transmission Line Reliability Projects		100	N/A		2
3	Transmission Substation Reliability		103	N/A		3
4	Renewal of Transmission Line Easements		104	N/A		4
5	Transmission Infrastructure Improvements		1145	N/A		5
6	Electric Transmission System Automation		3171	N/A		6
7	Fiber Optic for Relay Protection & Telecommunication		7144	N/A		7
8	Substation Security		8162	N/A		8
9	Condition Based Maintenance		9144	N/A		9
10	Synchronized Phasor Measurement		10138	N/A		10
11	Dynamic Line Ratings		11147	N/A		11
12	Automated Fault Location		12129	N/A		12
13	Composite Core Conductor		12130	N/A		13
14	ARC Detection		12131	N/A		14
15	SCADA Expansion		12132	N/A		15
16	Transmission Ceramic Insulator Replacement		99128	N/A		16
17	**TRANSMISSION LINE PROJECTS:**					17
18	13835 Tap at Talega	138kV	8158	Yes	2011 - 2012 Transmission Plan - Pg 424. No. 117, Table 7.1-1 Status of Previously Approved projects costing less than $50M	18
19	Transmission ROW Palos Verde- North Gila	500kV	12133	N/A	N/A	19
20	TL6927 EastGate-Rose Canyon	69kV	9151	Yes	2011 - 2012 Transmission Plan - Pg 424. No. 125, Table 7.1-1 Status of Previously Approved projects costing less than $50M	20
21	On Ramp Aerial Lighting	230kV	11144	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by FAA Compliance)	21
22	TL626 Reconductor	69kV	11148	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	22
23	TL629C- Reconductor	69kV	12135	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	23
24	Ramona Transmission Reliability	69kV	10140	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	24
25	Laguna Niguel- TL 13835 & TL 13837 Underground Conversion	138kV	11142	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	25
26	New Escondido - Ash #2	69kV	9160	Yes	2011 - 2012 Transmission Plan - Pg 423. No. 107, Table 7.1-1 Status of Previously Approved projects costing less than $50M	26
27	Replace TL617 Direct Buried Cable	69kV	11143	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by Aging Infrastructure)	27
28	TL6913 Poway - Pomerado	69kV	9138	Yes	2011 - 2012 Transmission Plan - Pg 423. No. 105, Table 7.1-1 Status of Previously Approved projects costing less than $50M	28
29	TL13821- Fanita Junction	138kV	9166	Yes	2011 - 2012 Transmission Plan - Pg 424. No. 114, Table 7.1-1 Status of Previously Approved projects costing less than $50M	29
30	Reconductor TL631 El Cajon - Los Coches	69kV	12154	Yes	2011 - 2012 Transmission Plan - Pg 428. No. 117, Table 7.2-1 New reliability projects found to be needed	30
31	TL613 (Old Town - PB) Cable Replacement	69kV	12126	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by Aging Infrastructure)	31
32	**SUBSTATION PROJECTS:**					32
33	Miguel Bank 60	138kV	6133	Yes	2011 - 2012 Transmission Plan - Pg 423. No. 105, Table 7.1-1 Status of Previously Approved projects costing less than $50M	33
34	69kV Capacitor Additions	69kV	9168	Yes	2011 - 2012 Transmission Plan - Pg 423. No. 106, Table 7.1-1 Status of Previously Approved projects costing less than $50M	34
35	Sweetwater Substation Rebuild	69kV	10125	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by Aging Infrastructure / Reliability)	35
36	69 /138kV Breaker Upgrades	69 / 138kV	9170	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	36
37	Emergency Equipment	69 / 138kV	6254	N/A	No ISO Transmission Reliability Upgrades Needed (Mobile Equipment to assist with repair of facilities)	37
38	Ocean Ranch (ET) Land Purchase	69 kV	5253	N/A	No ISO Transmission Reliability Upgrades Needed (Distribution Substation Land Purchase only)	38
39	Telegraph Canyon- add 4th Bank	138kV	7245	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by Distribution Expansion)	39
40	Penasquitos add 230kV Capacitor Bank	230 kV	12134	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	40
41	PICO Loop-in	138kV	12127	Yes	Submitted to the CAISO as an "Information Only" project not requiring CAISO approval.	41
42	Sycamore Add 69kV Reactors	69kV	12157	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by SDG&E Reliability Criteria)	42
43	Basilone Substation	69kV	11257	N/A	No ISO Transmission Reliability Upgrades Needed (Driven by Distribution Expansion)	43
44	Los Coches Bank 50 / 51	69 / 138kV	10135	Yes	2011 - 2012 Transmission Plan - Pg 424. No.120 &121, Table 7.1-1 Status of Previously Approved projects costing less than $50M	44

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS - TO4 CYCLE 1

	1	2	3	4	5	
Line No.	Project Name	Voltage	Budget Code	ISO Approval Status	Unless otherwise noted, page reference pertains to the 2011 - 2012 CA ISO Transmission Plan	Line No.
45	**WOOD TO STEEL PROJECTS:**					45
46	TL616 Wood to Steel Pole Replacement	69kV	9135	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	46
47	TL13804 Wood to Steel Pole Replacement	138kV	11138	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	47
48	TL 13812 (DOD- Camp Pendleton) Wood to Steel	138kV	10150	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	48
49	TL 690C (DOD- Camp Pendleton) Wood to Steel	69kV	8257	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	49
50	TL6914 Wood to Steel Pole Replacement	69kV	9136	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	50
51	TL 6912 (DOD- Camp Pendleton) Wood to Steel Pole	69kV	10149	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	51
52	Miguel Getaways- TL 628 & TL643 Wood to Steel	69kV	12147	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	52
53	TL 6910 Wood to Steel Pole Replacement	69kV	9134	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	53
54	TL649 Wood to Steel Pole Replacement	69kV	9137	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	54
55	TL 13825 Wood to Steel Pole Replacement	138kV	11156	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	55
56	TL 664 Wood to Steel Pole Replacement	69kV	11133	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	56
57	TL 6926 Wood to Steel Pole Replacement	69kV	9132	N/A	Wood to Steel Pole Replacement - to enhance reliabiltiy and reduce wildfire risks in fire and wind prone areas	57
58	**NETWORK UPGRADES TO ACCOMMODATE GENERATOR INTERCONNECTIONS**					58
59	Q493- Ocotillo Express	500kV	11146	Yes	Approved through ISO LGIA process.	59
60	Q337- Borrego Solar	69kV	7143	Yes	Approved through ISO LGIA process.	60
61	I.V. Bank 82	230 / 500kV	8163	Yes	Approved through ISO LGIA process.	61
62	Desert Star Transmission	230kV	10032	Yes	Approved through ISO LGIA process.	62
63	Q590- Campo Verde	230kV	12142	Yes	Approved through ISO LGIA process.	63
64	Q124-IV Solar AES, Q510-IV South, Q442-Centinela	230kV	8163, 11149, 11150	Yes	Approved through ISO LGIA process.	64
65	ECO- East County Substation	138/ 230 / 500kV	7139	Yes	Approved through ISO LGIA process.	65
66	Q468-Agua Caliente	500 kV	10142	Yes	Approved through ISO LGIA process.	66
67	**SUNRISE POWERLINK PROJECT:**					67
68	Sunrise Powerlink Project	69/ 138/ 230 / 500 kV	4138	Yes	2011 - 2012 Transmission Plan - Pg. 425, Table 7.1-2, No.9 Status of previously approved projects costing $50M or more.	68

Exhibit - SDG-7-3

CPUC Licensing

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS - TO4, CYCLE 1

	1	2	3	4	5	6	
Line No.	Project Name	Voltage	Budget Code	CPUC Authorization CPCN, PTC, Exempt or N/A See Note (1)	Filing Status See Note (2)	Comments	Line No.
1	**BLANKET BUDGET PROJECTS:**						1
2	Electric Transmission Line Reliability Projects		100	N/A	N/A	Assessed on specific project basis	2
3	Transmission Substation Reliability		103	N/A	N/A	Assessed on specific project basis	3
4	Renewal of Transmission Line Easements		104	N/A	N/A	Assessed on specific project basis	4
5	Transmission Infrastructure Improvements		1145	N/A	N/A	Assessed on specific project basis	5
6	Electric Transmission System Automation		3171	N/A	N/A	Assessed on specific project basis	6
7	Fiber Optic for Relay Protection & Telecommunication		7144	N/A	N/A	Assessed on specific project basis	7
8	Substation Security		8162	N/A	N/A	Assessed on specific project basis	8
9	Condition Based Maintenance		9144	N/A	N/A	Assessed on specific project basis	9
10	Synchronized Phasor Measurement		10138	N/A	N/A	Assessed on specific project basis	10
11	Dynamic Line Ratings		11147	N/A	N/A	Assessed on specific project basis	11
12	Automated Fault Location		12129	N/A	N/A	Assessed on specific project basis	12
13	Composite Core Conductor		12130	N/A	N/A	Assessed on specific project basis	13
14	ARC Detection		12131	N/A	N/A	Assessed on specific project basis	14
15	SCADA Expansion		12132	N/A	N/A	Assessed on specific project basis	15
16	Transmission Ceramic Insulator Replacement		99128	N/A	N/A	Assessed on specific project basis	16
17	**TRANSMISSION LINE PROJECTS:**						17
18	13835 Tap at Talega	138kV	8158	Exempt	Effective		18
19	Transmission ROW Palos Verde- North Gila	500kV	12133	N/A	N/A		19
20	TL6927 EastGate-Rose Canyon	69kV	9151	Exempt	Effective		20
21	On Ramp Aerial Lighting	230kV	11144	Exempt	Effective		21
22	TL626 Reconductor	69kV	11148	Exempt	Effective		22
23	TL629C- Reconductor	69kV	12135	Exempt	Effective		23
24	Ramona Transmission Reliability	69kV	10140	Exempt	Effective	Advice Letter 2355-E	24
25	Laguna Niguel- TL 13835 & TL 13837 Underground Conversion	138kV	11142	Exempt	Effective	Advice Letter 2326-E	25
26	New Escondido - Ash#2	69kV	9160	Exempt	Effective	Advice Letter 2338-E	26
27	Replace TL617 Direct Buried Cable	69kV	11143	Exempt	Effective		27
28	TL6913 Poway - Pomerado	69kV	9138	Exempt	Effective	Advice Letter 2395-E	28
29	TL13821- Fanita Junction	138kV	9166	Exempt	Pending	Advice Letter 2433-E. Suspended.	29
30	Reconductor TL631 El Cajon - Los Coches	69kV	12154	Exempt	Forecast		30
31	TL613 (Old Town - PB) Cable Replacement	69kV	12126	Exempt	Forecast		31
32	**SUBSTATION PROJECTS:**						32
33	Miguel Bank 60	138kV	6133	Exempt	Effective	Advice Letter 2261-E	33
34	69kV Capacitor Additions	69kV	9168	Exempt	Effective		34
35	Sweetwater Substation Rebuild	69kV	10125	Exempt	Effective		35
36	69 /138kV Breaker Upgrades	69 / 138kV	9170	Exempt	Forecast		36
37	Emergency Equipment	69 / 138kV	6254	N/A	N/A		37
38	Ocean Ranch (ET) Land Purchase	69 kV	5253	N/A	N/A		38
39	Telegraph Canyon- add 4th Bank	138kV	7245	Exempt	Effective		39
40	Penasquitos add 230kV Capacitor Bank	230 kV	12134	Exempt	Effective		40
41	PICO Loop-in	138kV	12127	Exempt	Forecast		41
42	Sycamore Add 69kV Reactors	69kV	12157	Exempt	Effective		42
43	Basilone Substation	69kV	11257	Exempt	Effective	Advice Letter 2364-E	43
44	Los Coches Bank 50 / 51	69 / 138kV	10135	Exempt	Effective		44

SAN DIEGO GAS & ELECTRIC COMPANY
FORECAST OF TRANSMISSION CAPITAL ADDITIONS - TO4, CYCLE 1

	1	2	3	4	5	6	
Line No.	Project Name	Voltage	Budget Code	CPUC Authorization CPCN, PTC, Exempt or N/A See Note (1)	Filing Status See Note (2)	Comments	Line No.
45	**WOOD TO STEEL PROJECTS:**						45
46	TL616 Wood to Steel Pole Replacement	69kV	9135	Exempt	Effective	Advice Letter 2246-E	46
47	TL13804 Wood to Steel Pole Replacement	138kV	11138	Exempt	Effective	Advice Letter 2379-E	47
48	TL 13812 (DOD- Camp Pendleton) Wood to Steel	138kV	10150	Exempt	Effective		48
49	TL 690C (DOD- Camp Pendleton) Wood to Steel	69kV	8257	Exempt	Effective		49
50	TL6914 Wood to Steel Pole Replacement	69kV	9136	Exempt	Pending	Advice Letter 2432-E. Suspended	50
51	TL 6912 (DOD- Camp Pendleton) Wood to Steel Pole Replacement	69kV	10149	Exempt	Forecast	`	51
52	Miguel Getaways- TL 628 & TL643 Wood to Steel	69kV	12147	Exempt	Forecast		52
53	TL 6910 Wood to Steel Pole Replacement	69kV	9134	Exempt	Pending	Advice Letter 2334-E Suspended	53
54	TL649 Wood to Steel Pole Replacement	69kV	9137	Exempt	Forecast		54
55	TL 13825 Wood to Steel Pole Replacement	138kV	11156	Exempt	Forecast		55
56	TL 664 Wood to Steel Pole Replacement	69kV	11133	Exempt	Forecast		56
57	TL 6926 Wood to Steel Pole Replacement	69kV	9132	Exempt	Forecast		57
58	**NETWORK UPGRADES TO ACCOMMODATE GENERATOR INTERCONNECTIONS**						58
59	Q493- Ocotillo Express	500kV	11146	Exempt	Effective	Advice Letter 2350-E	59
60	Q337- Borrego Solar	69kV	7143	Exempt	Effective		60
61	I.V. Bank 82	230 / 500kV	8163	Exempt	Effective		61
62	Desert Star Transmission	230kV	10032	N/A	N/A		62
63	Q590- Campo Verde	230kV	12142	Exempt	Effective		63
64	Q124- IV Solar AES, Q510- I.V South, Q442-Centinela	230kV	8163, 11149, 11150	Exempt	Effective		64
65	ECO- East County Substation	138 / 230 / 500 kV	7139	PTC	Effective	PTC Approved- June 21,2012 (A.09-08-003)	65
66	Q468- Agua Caliente	500 kV	10142	N/A	N/A		66
67	**SUNRISE PROJECT:**						67
68	Sunrise Powerlink Project	69/ 138/ 230 / 500 kV	4138	CPCN	Effective		68

Notes
(1) The term "Exempt" means the project is exempt from a Permit to Construct (PTC) or CPCN
(2) CPUC Approval Status is categorized as Effective, Pending or Forecast. Each category is defined as follows:
Effective - GO 131-D Approval Obtained or projects which are Categorically or Statutorily Exempt
Pending - under CPUC Review
Forecast - subject to Final Internal Determination
N/A - Not Applicable

Exhibit - SDG-7-4

Large Project Report

SDG&E's TO4 Cycle 1 Transmission Plant Additions
For 27-Month Forecast Period: June 2012 through August 2014
Reflects Costs and Benefits Related with Large Transmission Plant Additions

A. Summary

The following is a list of large transmission plant additions (in excess of $5 million) that will be placed into service during SDG&E's TO4 Cycle 1 Forecast Period (June 2012 through August 2014). Shown for each project are the in-service month, approval status, total cost, cost weighted for the number of months the project will be in service during the TO4 Cycle 1 rate-effective period (September 2013 through August 2014), and an explanation of the benefits of the project for SDG&E's retail and ISO wholesale customers.

Cost Totals ($000s):	Project Costs	Weighted Costs
	$2,381,193	$2,009,388

B. Projects

($000s)

Transmission Line Projects

1. Reconductor TL626

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11148	$ 5,216	$5,216	Sep 2012 Dec 2012	N/A	Exempt (Effective)	Emergency replacement of aging conductor in a high fire risk area after a conductor failure indicated the advance level of aging. Benefits are to improve reliability and lower the risk of fire.

2. Ramona Transmission Reliability

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
10140	$ 6,784	$ 6,784	Apr 2013	N/A	Advice Letter 2355-E (Effective)	This project will improve reliability of the Creelman Substation and the community of Ramona by separating joined infrastructure (two lines on common structures feeding the same substation), mitigating for heavy mechanical loading on the existing poles and fire hardening facilities on both TL635 and TL6917 to the Creelman Substation.

Transmisssion Line Projects- Continued

3. Laguna Niguel- TL13835 & TL13837

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11142	$ 12,402	$12,402	Apr 2013	N/A	Advice Letter 2326-E (Effective)	This project will improve reliability for the Laguna Niguel Substation and the communities of southern Orange County by removing the overhead transmission lines that traverse a canyon that is susceptible to landslides and erosion.

4. New Escondido – Ash #2

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09160	$ 18,427	$18,427	Jul 2013	Yes	Advice Letter 2338-E (Effective)	This project will improve reliability in the Escondido area consistent with NERC Reliability Standards.

5. Replace TL617 Direct Buried Cable

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11143	$ 10,995	$10,995	Jul 2013	N/A	Exempt (Effective)	This project will improve the reliability of the transmission system in La Jolla by replacing aging infrastructure.

Transmisssion Line Projects- Continued

6. Reconfigure TL 13821 – Fanita Junction

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09166	$ 29,917	$12,465	Apr 2014	Yes	Advice Letter 2433-E (Pending-Suspended)	This project will improve the reliability of the San Diego transmission system by mitigating Category B contingencies by the following: converting a three-terminal line into two, two terminal lines (SX-Carton Hills and SX-Santee), converting the Sycamore Canyon 138 kV bus from a ring bus to a breaker-and-a-half configuration, and increasing the outlet capability at Sycamore Canyon substation. TL13821 is currently configured as a three-terminal line, and is projected to experience thermal overloads following various Category B contingencies.

7. Reconductor TL631- El Cajon – Los Coches

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
12154	$12,477	$2,080	Jul 2014	Yes	Exempt (Forecast)	This project will increase the continuous rating of TL631 consistent with NERC Reliability Standards.

8. TL613 Cable Replacement

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
12126	$10,903	$1,817	Jul 2014	N/A	Exempt (Forecast)	This project will improve the reliability of the transmission system in Point Loma by replacing aging infrastructure.

Substation Projects

9. 69kV Capacitor Additions

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09168	$ 6,929	$ 6,721	Sep 2012 Jan 2013 Jul 2013 Oct 2013	N/A	Exempt (Effective)	These 69kV capacitors will improve the transmission voltage in the back country thereby improving the overall reliability to customers.

10. 69 / 138kV Breaker Upgrades

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09170	$ 7,049	$ 5,716	Jan 2013 Jan 2014	N/A	Exempt (Forecast)	Circuit breakers at these substations were identified using SDG&E standard replacement criteria during the annual short circuit study process. Replacing these breakers increases transmission system reliability by reducing risk of a failure of these breakers.

11. Emergency Equipment

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
06254	$ 7,200	$ 6,008	Apr 2013 May 2013 Jan 2014 Jun 2014	N/A	N/A	Having spare equipment for specific identified long lead items will enable SDG&E to respond to equipment failures in a timely fashion. Having equipment on hand with the asbuilted manufacturer drawings also helps enable accurate designs.

Substation Projects Continued

12. Los Coches Bank 50 / 51

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
10135	$ 7,115	$ 2,965	Apr 2014	Yes	Exempt (Effective)	The project will replace aging transformers with larger, standard size transformers. This will increase reliability, consistent with NERC reliability standards, and guard against overload occurrences.

Wood to Steel Projects

13. Wood to Steel Pole Replacement TL616

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09135	$9,700	$9,700	Jun 2012 Sep 2012	N/A	Advice Letter 2246-E (Effective)	This project will improve the reliability of this transmission line in fire and wind-prone areas and enhance reliability during fires. The project will rebuild approximately 4 miles of TL616 between Rancho Santa Fe, Lake Hodges and Bernardo substations. The project will replace approximately 58 wood poles with equivalent steel poles. The existing transmission conductor will be transferred to the new steel structures or replaced where necessary and will also result in increased vertical and horizontal spacing. New insulators, hardware and other equipment will be installed during the project. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

Wood to Steel Projects Continued

14. Wood to Steel Pole Replacement TL13804

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11138	$ 14,091	$14,091	Feb 2013	N/A	Advice Letter 2379-E (Effective)	The purpose of this project is to improve the reliability of the TL 13804 138kV Transmission Line by replacing approximately 55 wood H-frames (110 poles) with galvanized steel poles for a distance of roughly four miles. Portions of this TL will be omitted from the project scope for pole replacement due to it not being included in the Fire Threat Zone. The majority of TL 13804 traverses fire prone terrain and is located in an area with potential for high winds. The new structures will be designed for extreme wind loading, and will be fabricated using fire resistance materials. The immediate and long-term benefits from these pole replacements include improved electric reliability of the above mentioned infrastructure, as well as increased safety.

15. Wood to Steel Pole Replacement TL6914

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09136	$ 27,200	$20,400	Dec 2013	N/A	Advice Letter 2432-E (Pending-Suspended)	This project improves the reliability of the transmission line in fire and wind-prone areas. The project replaces approximately141 wood poles with equivalent steel poles between the Los Coches and Loveland substations for a distance of approximately 11.6 miles. The transmission conductor will be replaced where necessary. Phase spacing will be increased resulting in increased vertical and horizontal spacing. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds. This project improves the reliability of the transmission line in fire and wind-prone areas.

Wood to Steel Projects Continued

16. Wood to Steel Pole Replacement TL6912

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
10149	$ 12,237	$ 8,158	Jan 2014	N/A	Exempt (Forecast)	This project improves the reliability of the transmission line in fire and wind-prone areas. The project replaces approximately 80 wood poles with equivalent steel poles between the San Luis Rey and Pendleton substations for a distance of approximately 5.3 miles, replaced the transmission conductor where necessary and also results in increased vertical and horizontal spacing. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

17. Wood to Steel Pole Replacement TL6910

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09134	$9,712	$ 6,475	Jan 2014	N/A	Advice Letter 2334-E (Pending-Suspended)	This project will improve the reliability of this transmission line in fire and wind-prone areas and enhance reliability during fires. The project will rebuild approximately 4.5 miles of TL6910 between the Miguel and Border substations. The project will replace approximately 63 wood poles with equivalent steel poles. The existing transmission conductor will be transferred to the new steel structures, or replaced where necessary and will also result in increased vertical and horizontal spacing. New insulators, hardware and other equipment will be installed. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

Wood to Steel Projects Continued

18. Wood to Steel Pole Replacement TL649

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09137	$ 11,341	$ 4,725	Apr 2014	N/A	Exempt (Forecast)	This project improves the reliability of the transmission line in fire and wind-prone areas. The project replaces 135 wood poles with equivalent steel poles between the Otay, San Ysidro and Border substations for a distance of approximately 9 miles. The transmission conductor will be replaced, where necessary. Also, the project will result in increased vertical and horizontal conductor spacing. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

19. Wood to Steel Pole Replacement TL13825

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11156	$ 8,432	$ 3,513	Apr 2014	N/A	Exempt (Forecast)	This project improves the reliability of the transmission line in fire and wind-prone areas. The project replaces approximately 50 wood poles with equivalent steel poles between the Chicarita and Batiquitos substations for a distance of approximately 10 miles, replaces the transmission conductor where necessary and also results in increased vertical and horizontal spacing. Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

Wood to Steel Projects Continued

20. Wood to Steel Pole Replacement TL6926

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
09132	$15,345	$ 1,279	Aug 2014	N/A	Exempt (Forecast)	This project will improve the reliability of this transmission line in fire and wind-prone areas and enhance reliability during fires. The project will rebuild approximately 4 miles of TL6926 between the Rincon and Valley Center substations. This project will replace approximately 45 wood poles with equivalent steel poles, replace the transmission conductor where necessary and will also result in increased vertical and horizontal spacing. It will also convert an existing 2 mile overhead span to underground. Less insulator contamination, less maintenance, a longer equipment life span, Benefits from these changes include less insulator contamination, less maintenance, a longer equipment life span, improved avian protection and increased reliability in high winds.

Network Upgrades to Accommodate Generator Interconnections

21. Q493-Ocotillo Express

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
11146	$40,000	$40,000	Dec 2012 Feb 2013 Jun 2013	Yes, via the LGIA Process	Advice Letter 2350-E (Effective)	This project interconnects renewable energy resources to the grid and helps SDG&E meet its obligation under the CA state RPS goal. The Interconnection will connect a 299 MW wind renewable generation project to the Sunrise Powerlink. The Network facilities to be constructed include a 500 kV switchyard to accommodate the TL50003 (Sunrise Powerlink) loop-in.

Network Upgrades to Accommodate Generator Interconnections Continued

22. Q337-Borrego Solar

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
07143	$7,979	$7,979	Jan 2013	Yes, via the LGIA process	Exempt (Effective)	The project provides greater reliability to the Borrego community, while also contributing to the State mandated renewable energy targets. The Borrego substation property will be modified to accommodate the interconnection of the 26 MW NRG Borrego Solar 1 Project. The expansion at this substation is expected to be about 1.4 acre in size and would be located on the south side of the existing substation. Equipment that will be added includes a cable pole where 69 kV TL687 would enter, conductor and insulators, a new 69 kV busbar, breakers, disconnect switches, and control equipment. The expanded area will be fenced with security fencing similar to that currently at the existing substation.

23. I.V. Bank 82

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
08163	$13,074	$13,074	Apr 2013	Yes, via the LGIA process	Exempt (Effective)	The IV Bank 82 project will support interconnection and full deliverability of renewable generation at the IV Substation. Additionally, adding IV. Bank 82 reduces the risk of losing generation capacity on the 500 kV transmission lines which may result in load curtailment. The combined capacity of the existing 500/230 kV transformer banks at IV substation is currently not sufficient to provide full deliverability for the new renewable generation projects connecting to IV substation in addition to the existing generators connected to IV substation. Loss of either of the existing transformer banks (80 or 81) at IV Substation will limit the energy transfer from the 230 kV to 500 kV system and will thus limit energy and capacity available to the 500 kV transmission system and SDG&E customers. This energy availability has become more critical with unavailability of SONGS generators as all import energy into San Diego must be transported by the 500 kV transmission lines from the Imperial Valley or the 230 kV transmission lines from Orange County (excluding the limited capacity available from CFE through Path 45).

Network Upgrades to Accommodate Generator Interconnections Continued

24. Desert Star Transmission

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
10032	$ 26,528	$26,528	Jun 2013	Yes, via the LGIA process	N/A	The project will enable the 480 MW Desert Star Combined Cycle plant to be fully dispatched into the California ISO territory. It also allows for 419.25 MW to be counted towards the Resource Adequacy (RA) capacity requirement for SDG&E to meet its obligation.

25. Q124- AES Solar, Q510- I.V. South, Q442- Centinela

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
8163 11149 11150	$9,025	$6,017	Jan 2014	Yes, via the LGIA process	Exempt (Effective)	This Network Upgrade enables the interconnection of renewable projects to the CAISO controlled grid. The photovoltaic projects help SDG&E meet its obligation under the CA state RPS goal.

26. ECO- East County Substation

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
07139	$406,712	$135,532	May 2014 Through Aug 2014	Yes, via the LGIA Process	PTC approved Jun 2012	The proposed ECO Substation Project will provide an interconnection hub for renewable generation along SDG&E's existing Southwest Powerlink (SWPL) 500-kilovolt (kV) transmission line. In addition to accommodating the region's planned renewable generation, the project will also provide a second source for the southeastern 69 kV transmission system that avoids the vulnerability of common structure outages, which would increase the reliability of electrical service for Boulevard, Jacumba, and surrounding communities. The second source provided by the ECO project will allow for faster restoration during forced outages, and will greatly reduce the impacts of scheduled maintenance outages. The proposed project will provide interconnection capability at three voltage levels (500, 230, and 138 kV), which will provide renewable generators the option to connect at a voltage level that is appropriately sized for their project. Without the flexibility for interconnection that the ECO project provides, integrating renewable generation projects would be much more costly for SDG&E ratepayers.

27. Q468-Agua Caliente

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
10142	$18,776	$4,694	Jun 2014	Yes, via the LGIA process	N/A	The new Hoodoo Wash switchyard was constructed to facilitate the interconnection of the Agua Caliente photovoltaic project. The Agua Caliente project utilizes a renewable resource and will help meet the California state RPS goal.

Sunrise Project

28. Sunrise Powerlink

Budget Code	Cost of Project	Weighted Cost	In Service Date	ISO Approved	CPUC Approved	How Project Benefits Customers
04138	$1,615,627	$1,615,627	Jun 2012 through Jun 2013	Yes	CPCN (Effective)	The Sunrise Project was approved by the California Public Utilities Commission ("CPUC") in "Decision Granting a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project," issued December 18, 2008 ("Decision" or "CPCN").[1] The Decision found that Sunrise would: (1) enhance regional reliability[2] and mitigate congestion within the National Interest Electric Transmission Corridor, [3] (2) advance the State's renewable goals of reducing greenhouse gas emissions through renewable generation procurement at a 33% Renewable Portfolio Standards by 2020 by facilitating the development of renewable generation in the Imperial Valley area[4] and (3) provide economic benefits to customers utilizing the transmission grid operated by the California Independent System Operator.

[1] Decision ("D.") 08-12-058, 2008, Cal. PUC LEXIS 534. http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/95750.PDF.

The CPUC's website contains all of the procedural filings, including SDG&E's application at the following link: http://docs.cpuc.ca.gov/published/proceedings/A0608010.htm.

In addition, all of the environmental documents are located on the CPUC's website at the following link: http://www.cpuc.ca.gov/Environment/info/aspen/sunrise/sunrise.htm.

[2] D.08-12-058 found that there exists a "reliability need" for SDG&E's service area by 2014 and perhaps sooner, given the many uncertainties in the modeling assumptions adopted in the decision. Finding of Fact 7, *mimeo* at 283.

[3] 72 Fed. Reg. 56992 (October 5, 2007). The DOE designated two National Interest Electric Transmission Corridors pursuant to section 204 of the Federal Power Act, 16 USC §824o, one of which encompasses San Diego County. *Id.* at 57025.

[4] *Id.*, Findings of Fact 15 and 19.

VERIFICATION

STATE OF CALIFORNIA)
) ss.
COUNTY OF SAN DIEGO)

John D. Jenkins, being duly sworn, on oath, says that he is the John D. Jenkins identified in the foregoing prepared direct testimony; that he prepared or caused to be prepared such testimony on behalf of San Diego Gas & Electric Company; that the answers appearing therein are true to the best of his knowledge and belief; and that if asked the questions appearing therein, his answers would, under oath, be the same.

John D. Jenkins

John D. Jenkins

STATE OF California,
CITY/COUNTY OF San Diego, to-wit:

On this 11th day of February, 2013 before me, ANNIE VICTORIA RUIZ, a Notary Public, personally appeared John D. Jenkins, who proved to me on the basis of satisfactory evidence to be the person whose name is subscribed to the within instrument and acknowledged to me that he executed the same in his authorized capacity, and that by his signature on the instrument the person, or the entity upon behalf of which the person acted, executed the instrument.

I certify under PENALTY OF PERJURY under the laws of the State of California that the foregoing paragraph is true and correct.

WITNESS my hand and official seal.

Annie Victoria Ruiz

ANNIE VICTORIA RUIZ
COMM. #1877490
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SAN DIEGO COUNTY
Commission Expires Jan 18, 2014