BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	)	Rulemaking 08-08-009 (Filed August 21, 2008)

MOTION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) TO AMEND 2012 DRAFT RENEWABLE PROCUREMENT PLAN

(PUBLIC VERSION)

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OF THE STATE OF CALIFORNIA

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In accordance with the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission"), the *Assigned Commissioner's Ruling Identifying Issues and Schedule of Review for 2012 Renewables Portfolio Standard Procurement Plans Pursuant to Public Utilities Code Sections 399.11 et seq. and Requesting Comments on New Proposals* (the "ACR") issued in the above-captioned docket on April 5, 2012, and the *Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans* (the "ALJ Ruling") issued in the above-captioned docket on August 2, 2012, San Diego Gas & Electric Company ("SDG&E") hereby requests authority to amend its draft 2012 Renewables Portfolio Standard ("RPS") Procurement Plan and related Appendix C filed on May 23, 2012.

In the ACR, the Commission established a schedule for submission of draft Plans. Under the schedule set forth in Attachment A to the ACR, the investor-owned utilities ("IOUs") were required to file draft Plans on May 23, 2012, and motions for final updates to Plans on August 1, 2012. In the ALJ Ruling, the Commission extended this latter date to August 15, 2012. In accordance with the Commission's direction, SDG&E has attached hereto the following:

- ***Attachment 1*: Amended Draft 2012 Plan** – SDG&E has updated the discussion of its RPS need assessment and the accompanying quantitative information included in the Draft Plan to reflect the requirements contained in the ALJ Ruling. The update includes adjustments to SDG&E's retail sales forecasts, risk assessment of pre-approved procurement programs and banking assumptions. In addition, consistent with the direction set forth in the ALJ Ruling, SDG&E has added a discussion of a voluntary minimum margin of over-procurement.
- ***Attachment 2*: Amended Appendix C – Evaluation Methodology (LCBF Process)** – SDG&E has added language to clarify how it intends to evaluate unbundled renewable energy credit ("REC") bids and has clarified its analysis of capacity attributes by including both its Energy Only and Full Capacity Time of Day Factors.
- ***Attachment 3*: Redline Plan Document** – Document shows changes from the draft Plan submitted on May 23.
- ***Attachment 4*: Redline Appendix C** – Document shows changes from the version of Appendix C submitted on May 23.

A complete version of SDG&E's amended draft 2012 RPS Plan is available on its website at the following link: http://sdge.com/regulatory-filing/3620/order-instituting-rulemaking-continue-implementation-and-administration. SDG&E respectfully requests that the Commission grant this motion to amend its filing and that it expeditiously approve its draft Plan.

Respectfully submitted this 15th day of August, 2012.

/s/ *Aimee M. Smith*

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Attachment 1
Amended Draft 2012 Plan

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SDG&E 2012 RPS PROCUREMENT PLAN

I. ASSESSMENT OF RPS PORTFOLIO SUPPLIES AND DEMAND - § 399.13(A)(5)(A)

A. Overview

SDG&E's 2012 RPS Procurement Plan ("RPS Plan") describes how SDG&E will determine its procurement needs and how it will manage its RPS portfolio to ensure that it meets RPS compliance targets in a cost effective manner. The RPS Plan is designed to procure Least Cost Best Fit ("LCBF") renewable eligible resources so that SDG&E can serve its customers achieving the following levels of deliveries by Compliance Period ("CP"): (a) with an average of 20% of retail sales between January 1, 2011 and December 31, 2013, inclusive[1] ("CP1") (b) with 25% of retail sales by December 31, 2016, with reasonable progress made in 2014 and 2015[2] ("CP2"); (c) with 33% of retail sales by December 31, 2020, with reasonable progress made in 2017, 2018 and 2019[3] ("CP3"); and (d) with 33% of retail sales in each year beyond 2020[4] ("Post 2020 CP"). In order to determine how much energy to procure to meet these needs, SDG&E will follow the Need Determination Methodology described below. SDG&E will implement a work plan to fulfill its need, including soliciting additional multi-product and multi-term contracts through RPS solicitations, considering bilateral proposals, utilizing banked procurement, selling surplus generation when appropriate, and pursuing utility tax equity investment opportunities and/or utility ownership when economical and prudent.

B. Need Determination Methodology

SDG&E makes procurement decisions based on how its risk-adjusted RPS position forecast (referred to herein as its "RPS position") compares to RPS compliance requirements, the result of which is its probability-weighted procurement need or Renewable Net Short ("RNS"). In order to calculate its RPS Position, SDG&E assigns a probability of success, following a qualitative and quantitative

[1] Compliance towards Compliance Period 1 goals shall be measured in accordance with D.11-12-020, Ordering Paragraph ("OP") 1.
[2] Compliance towards Compliance Period 2 goals shall be measured in accordance with D.11-12-020, OP 2.
[3] Compliance towards Compliance Period 3 goals shall be measured in accordance with D.11-12-020, OP 3.
[4] Compliance towards Post 2020 Compliance Period goals shall be measured in accordance with D.11-12-020, OP 4.

assessment, to the expected deliveries for each project in its portfolio[5] and then adds the risk-adjusted expected deliveries across all projects in its entire RPS portfolio. Probabilities are used because renewable projects and their deliveries are exposed to multiple risks and the flexible compliance mechanisms that allowed for borrowing from future procurement have been eliminated by recent legislation.[6] These risks include approval risks (for example, Commission approval and the timing of it), development risks (for example, permitting, financing, or transmission inter-connection), delivering risks (for example, generation fluctuations given the variant-intermittent nature of some renewable resources, or operational challenges), or other risks (for example, under-development transmission infrastructure common to a group of projects).

In general, if SDG&E's RPS Position is less than the RPS requirements, SDG&E will likely procure additional resources. If the RPS Position is greater than the RPS requirements, SDG&E will consider opportunities to bank or sell surplus generation. In addition, in order to optimize the relative value of renewable energy across compliance periods, SDG&E also considers short-term contracts when, for example, it is short[7] in the most immediate CP but long in the subsequent CP. SDG&E strives to have a well-diversified RPS portfolio so that its RPS compliance, particularly in the most immediate compliance period, is not unduly exposed to any given risk (for example, to a given technology, region, counterparty, etc.). SDG&E's RPS portfolio management strategy involves identifying needs and risks and managing them as well as possible in a cost effective way.

The following sections explain SDG&E's methodology for determining its RNS. First, the process to compute the RPS Position is explained. Then, needs by compliance periods are inferred by comparing RPS requirements to the RPS Positions .

1. The Assessment of Probability of Success for Various Project Types as a Key Component of Calculating RNS

[5] For purposes of determining its RPS Position, SDG&E considers its portfolio to include all executed contracts until contract expiration (*e.g.* it does not assume expiring contracts will be renewed and excludes contracts under-negotiation unless indicated otherwise) and tax equity and UOG projects where relevant progress has been made (for example, Shu'luuk).

[6] Senate Bill (SB) 2 (1X)

[7] Throughout this document, the word "short" is used when the RPS Position is lower than the relevant RPS requirements and "long" when the RPS Position is higher than relevant RPS requirements.

SDG&E must assess the probability of success of the following main types of projects: (a) delivering; (b) approved but not yet delivering; and (c) not yet approved.[8] SDG&E evaluates the probability of success for each project in its portfolio on a monthly basis in order to calculate its RNS, which is the basis for its procurement needs. To do this, SDG&E conducts a monthly review with an interdisciplinary team and uses the most up-to-date qualitative and quantitative information to assign a probability of success to each individual project. SDG&E's most up-to-date assessment is set forth in Section V below. SDG&E applies the following methodology to analyze each project type:

a. *Assessment of the Performance of Delivering Projects*

Projects that have already achieved commercial operation and begun delivering energy provide the most stable source of RPS energy when forecasting RPS procurement needs. These projects have overcome development hurdles and receive a steady stream of income from their Power Purchase Agreement ("PPA"). However, it is crucial to consider the potential fluctuations in deliveries that these projects can experience and the impact that such fluctuations could have on SDG&E's need to procure additional resources to meet RPS goals. As discussed further in Section IV below, deliveries from these projects can be impacted by resource availability, regulatory changes, economic environment, operational performance, and evolving technologies. These types of fluctuations can be significant. For example, deliveries from a selection of SDG&E's wind portfolio differed by approximately 275 GWhs between 2010 and 2011, which equates to nearly 2% of SDG&E's 2010 retail sales. In order to ensure RPS compliance, SDG&E must account for these types of fluctuations, (and recognize the swings in production could be positive). The monitoring of performance of delivering contracts and the assessment of probabilities focuses on (a) understanding the historical profile of generation of each project and how it has differed year on year and relative to forecasts, and (b) the operational track record of any given generation. If the fluctuations in generation have been high and/or the operational track record has been poor, SDG&E assigns a lower than 100% probability, which typically ranges from 90-95% across the portfolio. Adjusting forecasts when necessary is a crucial component of SDG&E's need assessment methodology.

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[8] See the Renewable Net Short Calculation in Section V below.

b. Assessment of the Development Progress of CPUC Approved Projects That Have Not Yet Begun Delivering

Another important aspect of SDG&E's need assessment methodology is evaluating the development status of projects that the CPUC has approved, but have not begun delivering energy. These projects are typically much more risky than projects that have begun delivering because of the potential barriers that can arise during the development process to prevent a project from being built. Permitting, interconnection, financing and other development issues are discussed further in Section III below. SDG&E currently estimates that projects in development will have approximately a 60% success rate on average,[9] making the monitoring of development status the most critical aspect of SDG&E's need assessment methodology. SDG&E must account for development risks when determining its procurement needs. As with delivering contracts, SDG&E meets internally on a monthly basis to assign a probability of success to each of its developing projects. SDG&E's current is assessment is provided in the Renewable Net Short Calculation in Section V below.

c. Assessment of the Approval Queue for Projects that SDG&E Has Submitted to the CPUC, But Have Not Yet Been Approved

SDG&E meets at least monthly with Energy Division staff to discuss the likely approval timetable of projects that SDG&E has submitted to the CPUC for approval. The discussion focuses on when the Energy Division expects the Commission to act on such contracts and any potential timing constraints that might necessitate expedited Commission action or additional information needed. Since the Commission has indicated that it can take action on only one contract per business meeting,[10] SDG&E works collaboratively with the Commission to develop a work plan that results in timely approval. It is possible, however, that the shortage of Energy Division staff or other procedural challenges can result in approval delays that can impact a project's ability to come online. SDG&E must monitor this process closely to determine what, if any, impact it may have on the timing of expected deliveries.

2. Assess Other Portfolio Risk Factors

[9] See section 6.5 for a list of SDG&E's risk assessment for each individual project.
[10] E-mail from Julie Fitch, former Energy Division Director, dated December 18, 2009.
10

Once SDG&E has determined the probability of success for each of the contracts in its portfolio, SDG&E must also consider broader risk factors that can impact multiple projects or its entire portfolio, including: (a) fluctuations in retail sales; (b) the progress of key transmission upgrades/infrastructure; (c) contract termination (d) banking rules; (e) potential deficit from the prior RPS regime; and (f) the market for resale of surplus procurement. SDG&E evaluates the impact that each of these factors has on its portfolio on a monthly basis. SDG&E describes its methodology for analyzing these risk factors below.

a. Impact of Retail Sales Fluctuations

Since RPS compliance is based on a GWh target that is calculated using a percentage of retail sales, it is important to monitor fluctuations in forecasted retail sales. Up until July of 2012, SDG&E used a retail sales forecast based on the California Energy Demand 2010-2020 Staff Revised Forecast Second Edition[11].At present, in accordance with the Commission's guidance,[12] SDG&E uses a forecast based upon the methodology determined in the 2010 LTPP bundled plans. The Commission explains that the 2010 LTPP decision[13] allows utilities to "use their own forecasts for bundled retail sales for the first five years and use the LTPP standardized planning assumptions thereafter[14]". Since SDG&E's current retail sales forecast is lower than the forecast used in its initial 2012 RPS Plan filing[15], SDG&E's current RNS is also lower. SDG&E monitors its retail sales forecasts on a monthly basis in order to identify potential fluctuations and their impact to its RPS requirements.

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[11] Kavalec, Chris and Tom Gorin, 2009. California Energy Demand 2010-2020, Staff Revised Forecast – Second Edition. California Energy Commission. CEC-200-2009-012-SF-REV. SDG&E adjusted the actual RPS forecast in April 2010 to align the RPS forecast with a rate case forecast, resulting in forecast loads approximately 1% lower than the bundled retail sales presented for SDG&E in the original CEC forecast. This adjustment had an immaterial impact to SDG&E's RPS need assessment.

[12] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012.

[13] D.12-01-033 (Decision Approving Modified Bundled Procurement Plans dated January 12, 2012).

[14] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012.

[15] San Diego Gas & Electric Company (U 902 E) 2012 Draft Renewable Procurement Plan, dated May 23, 2012.

b. Impact of Solar Panel Degradation

Contracts with solar PV developers incorporate a degradation factor which is used to forecast the project's performance over time as the panels age and become less efficient. As part of its RPS position calculation (both nominally[16] and probability weighted), SDG&E incorporates this contractual degradation factor in its probability weighted delivery. However, actual degradation can be higher or lower than the contractual degradation assumed. Over the next 2 years, as most of the larger Solar PPAs come online, SDG&E will add the monitoring of this variable as part of its RPS portfolio management practices.

c. Impact of Key Transmission Upgrades and/or Infrastructure

Transmission has long been recognized as a barrier to achieving RPS goals. SDG&E monitors the status of key transmission upgrades, such as the Eco DREW Substations, on which multiple SDG&E RPS projects depend, in order to assess the potential impact of their delay or failure. Absent the deliveries that rely on these three key upgrades, SDG&E's need would increase materially, as shown in Table 2 in Section V below. The analysis presented bv SDG&E herein assumes that these transmission upgrades will be completed according to the current schedule. SDG&E continues, however, to monitor the progress of these transmission upgrades in order to assess potential delays and the corresponding potential need for incremental purchases.

d. Impact of Contract Renewal

SDG&E began signing RPS contracts in 2003, most of which had terms of 20 years. Some of these contracts are expected to deliver through 2023, and will impact SDG&E's procurement needs for the post 2020 Compliance Period. Some contracts for renewable energy procurement, however, were signed before the institution of the RPS program. Some of these contracts are scheduled to terminate during Compliance Period 2 and Compliance Period 3. As part of its RPS position calculation, and in accordance with Commission direction[17], SDG&E does not assume that these projects will be renewed. Owners of these projects will be asked to bid such projects

[16] Nominal RPS position refers to a position estimated assuming that deliveries from contracts will occur as expected 100% of the time.

[17] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012

into future RFOs to compete with other options that SDG&E has at that time. SDG&E believes that ratepayers will benefit from this additional supply being submitted into competitive solicitations.

e. *Impact of Contract Termination*

As part of its contract administration process, SDG&E actively monitors upcoming contractual conditions precedent that developers must meet (or waived) in order for the contract to continue to be viable. When SDG&E is the beneficiary of a condition precedent that may not be or has not been met, SDG&E will consider terminating the contract.

f. *Impact of Banking Rules*

RPS rules allow SDG&E to bank excess procurement from one compliance period for use in another, with exceptions for short term contracts and products that meet requirements for § 399.16(b)(3) products ("Category 3").[18] In accordance with Commission direction[19], SDG&E assumes for purposes of calculating its RNS that eligible excess procurement[20] will be utilized in future compliance periods[21]. SDG&E's excess procurement position will be impacted by whether the Commission permits SDG&E to include generation from its Cabazon and Whitewater Green Attributes Purchase and Sales Agreements ("GAPSAs") in its excess procurement bank. SDG&E has explained that these agreements meet the requirements for contracts to "count in full" towards RPS requirements, and that such grandfathered contracts should count towards its excess procurement bank.[22] The Commission has directed that grandfathered contracts do count towards excess procurement, but it has not yet provided direction on whether the GAPSAs qualify as grandfathered contracts. The Commission's direction on this issue will determine whether SDG&E is able to carry forward a potential excess

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[18] Public Utilities Code § 399.13(a)(4)(B). All statutory references herein are to the Public Utilities Code unless otherwise noted.

[19] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012

[20] Rules regarding excess procurement are set forth in D.12-06-038 (Decision Setting Compliance Rules for the Renewables Portfolio Standard Program dated June 27, 2012).

[21] Note that SDG&E may also manage excess procurement by selling such products when doing so would benefit ratepayers.

[22] *San Diego Gas & Electric Company Opening Comments on July 15, 2011 Ruling Requesting Comments on New Procurement Targets and Certain Compliance Requirements for the Renewable Portfolio Standard Program*, filed August 30, 2011 in R.11-05-005.

procurement bank in CP1.[23] In CP 2, SDG&E expects that it will be able to bank potential excess procurement (into CP3) under all of the scenarios that have been contemplated by the Commission.

g. Impact of the Deficit From 2010 RPS Program

Based on the Commission's recent decision on RPS compliance rules,[24] SDG&E must carry forward a deficit from the former RPS regime, which required that retail sellers achieve 20% by 2010. Although SDG&E met these goals based on prior flexible compliance rules,[25] the decision indicates that SDG&E must carry forward a deficit into CP1. SDG&E has incorporated this deficit in its need assessment for CP1 based on the methodology provided by the decision. SDG&E's calculation of this deficit is provided at Table 3 in Section V below.

h. Impact of the Resale Market

SDG&E will closely monitor opportunities to sell excess procurement. SDG&E will assess the market when the opportunities arise to determine whether banking such excess procurement for use in a future compliance period or trying to sell it in the market is more advantageous for SDG&E ratepayers. If SDG&E believes that the current market price is high and expects that it will be able to fulfill any future needs with more economic options, it may choose to sell excess procurement instead of banking it.

i. Impact of Rim Rock Settlement

In July of 2011, the Commission approved a settlement agreement between SDG&E, NaturEner Rim Rock Wind Energy, LLC, the Division of Ratepayer Advocates ("DRA") and The Utility Reform Network ("TURN") (together, the "Settling Parties") to make a tax equity investment in the Rim Rock wind project located in Montana.[26] As part of the settlement agreement, SDG&E – subject to Rim Rock becoming operational and SDG&E making a tax equity investment in the project – agreed not to procure any incremental RECs from projects that are neither directly connected nor dynamically scheduled to a California-based Balancing Area Authority ("CBA")

[23] See the RPS Banking Analysis table in Section V below
[24] *Decision Setting Compliance Rules for the Renewable Portfolio Standard Program*, *supra*, note 20.
[25] SDG&E's August 2011 RPS Compliance Filing dated August 1, 2011.
[26] *See* D.11-07-002.

if such purchase would cause SDG&E to meet more than 25% of its RPS requirements with such RECs through December 31, 2017. Since SDG&E has already procured this type of out-of-state generation up to the 25% limit established by the settlement, SDG&E is currently precluded from purchasing RECs from out-of-state projects that are not dynamically scheduled to a CBA, through the end of 2017. If Rim Rock does not become commercially operational or SDG&E does not make its tax equity investment in Rim Rock, this restriction will be removed and SDG&E will consider additional REC purchases in the period between 2012 and 2017.

3. Determine RNS for Each Compliance Period

After probabilities are assigned to each project, SDG&E's RNS is calculated by multiplying the forward contractual delivery profiles (including degradation) of each project by each project's probability and then adding those generation profiles across the portfolio.[27] The discussion below describes SDG&E's current forecasted RNS for each compliance period based on its assessment as of August, 2012. More detail on SDG&E's needs in each compliance period is provided in Section V below.

a. Compliance Period 1 Procurement Needs

SDG&E intends to meet CP1 goals by maintaining a 20% procurement level in 2011, 2012, and 2013 on average. Based on deliveries from SDG&E's current portfolio of executed contracts, before applying any risk adjustment, SDG&E would be able to meet CP1 requirements without additional procurement. Based on the risk adjusted portfolio in CP1, in order to meet the 20% requirement, SDG&E may have to conduct a relatively small unbundled REC purchase (in accordance with the Rim Rock settlement discussed in (I)(B)(2)(i) above) to offset the deficit carried into CP1. Going forward, if relative to the current risk adjusted position, delivering projects underperform, developing projects fail or are delayed or if CPUC approvals are delayed (or not obtained), SDG&E will make additional purchases focusing on short term contracts (emphasis on in-state unbundled RECs[28]). The rationale for focusing on either unbundled RECs or short-term bundled contracts is minimizing ratepayer cost in light of SDG&E's position in

[27] As explained above, SDG&E's practice is to exclude contracts under-negotiation and to not assume renewal for an expiring contract.
[28] The strategy will be different if multiple large projects fail and SDG&E must replace large portions of its portfolio.

CP2. Lastly, if the generation from the relatively large volume of SDG&E projects anticipated to begin delivering in 2013 materially surpasses the current probability assessed profile and the Commission does not grant grandfathered status to the Shell GAPSAs, SDG&E may become a seller in mid-to-late 2013.

b. Compliance Period 2 Procurement Needs

Based on current projections, SDG&E expects that it will meet Compliance Period 2 RPS goals with generation from contracts that have been executed together with the deliveries of tax equity and UOG initiatives where relevant progress has been made.[29] SDG&E intends to manage potential over-procurement by banking it for future compliance needs, terminating contracts where conditions precedent are not met, and/or selling such excess procurement.

c. Compliance Period 3 Procurement Needs

Based on SDG&E's current probability weighted RPS position forecast, the company may need to conduct new renewable eligible purchases (from either new greenfield projects, renewal upon expiration of existing contracts, or other available existing facilities) to meet its CP3 RPS requirement, 33% by 2020. The level of new purchases will be subject to the level of banking, if any, related to potential excess procurement in CP2 into CP3. SDG&E intends to fill this remaining need with viable low-cost opportunities from solicitations in 2012, 2013 and 2014, and with potential tax equity investments.

4. Utility Tax Equity Investment and Utility Ownership Opportunities

SDG&E participation as a tax equity investor in renewable projects enhances project viability (through securing of financing) and decreases costs for ratepayers (given SDG&E's cost of capital relative to renewable financing market). Tax equity investments by utilities and other non-traditional investors are particularly important in the future in light of the phase out of the Cash Grant.[30] Without the Cash Grant, developers without a sizable balance sheet rely on tax equity investors to monetize renewable incentives such as the Investment Tax Credit.

[29] Includes Shu'luuk Wind and the Solar Energy Program.

[30] The American Recovery and Reinvestment Act of 2009 (H.R. 1), enacted in February 2009, created a renewable energy grant program that is administered by the U.S. Department of Treasury. This cash grant may be taken in lieu of the federal business energy investment tax credit ("ITC").

SDG&E's experience with tax equity investment has been favorable. The Rim Rock project (discussed above) was approved by the CPUC and the Federal Energy Regulatory Commission ("FERC") and has an expected online date in Q4 2012.[31] SDG&E's Shu'luuk project is currently under negotiation for an expected online date in 2014. SDG&E intends to submit this project for Commission approval in 2012. Anticipated deliveries from these projects have been incorporated into SDG&E's forecasted RPS procurement need based on the probability of success that SDG&E assigned to them according to the process described above. SDG&E is also considering additional tax equity investment opportunities in two to three projects where: (a) its involvement might enhance viability of a project with an existing contract; and/or (b) where a promising cost competitive project with an online date just prior to the start of CP3 may have a positive socioeconomic impact, potentially involving a Diverse Business Enterprise.

SDG&E also continues to make progress on its Solar Energy Project,[32] pursuant to which SDG&E will build 26 MWs of utility-owned solar photovoltaic projects. SDG&E held a request for proposals in the fall of 2011 and is currently negotiating contracts with shortlisted contractors. SDG&E expects construction on these projects to begin in 2014. Anticipated deliveries from these projects have been incorporated into SDG&E's RPS procurement need forecast. Additional UOG opportunities are not anticipated at this time, but may be considered if economic and prudent.

II. POTENTIAL COMPLIANCE DELAYS- § 399.13(A)(5)(B)

The market for renewable energy is dynamic; multiple factors can impact project development and SDG&E's attainment of its RPS goals. The following discussion covers the major issues affecting both renewable project developers and SDG&E. It begins with the transmission, permitting, and financing hurdles faced during project development, and continues through the challenges experienced as a project matures – viability, debt equivalence, accounting issues, and regulatory uncertainty.

[31] D.11-07-002.
[32] Approved by D.08-07-017.

A. Transmission & Permitting

1. Interconnection Facility Delays

The timely approval, permitting, and completion of interconnection facilities are crucial to the successful development of SDG&E's renewable portfolio. Currently, the key transmission facilities that impact SDG&E's portfolio are: the ECO sub-station and the DREW switchyard. Unsuccessful development of these facilities will materially impact SDG&E's renewable portfolio.

Existing transmission constraints between the Imperial Valley and the San Diego load center have been largely resolved with the construction of the Sunrise Powerlink. However, the addition of the Sunrise Powerlink and the signing of multiple PPAs in the Imperial Valley region do not, by themselves, guarantee the successful construction and interconnection of renewable generation facilities. SDG&E and developers are now focused on building the interconnection and network facilities necessary to interconnect and deliver this renewable energy to the transmission system, and they are facing significant permitting challenges. An example of these interconnection facilities is the proposed 230 kV "DREW" switchyard in Imperial Valley that will act as a collector switchyard for multiple renewable projects to connect to the transmission system with one line, reducing environmental impacts. However, as with any new construction of transmission infrastructure, there are environmental, permitting issues, and other challenges (mainly uncooperative land owners, and/or opposition from nearby residents) that can impede timely progress. Permitting has proven particularly difficult where land owners or permitting authorities have their own commercial interests that may compete with those of the renewable developers. Additionally, as is the case with the proposed ECO substation, which is designed to improve grid reliability for Eastern San Diego and also serve as a hub to connect and deliver renewable projects to San Diego, regulatory approvals are still pending causing uncertainty developers whose projects rely on this upgrade.

2. Interconnection Study Process

The California Independent System Operator's ("CAISO") process for determining required upgrades for renewable projects can cause significant delay and expense. SDG&E protects ratepayers by establishing transmission upgrade cost limits and including conditions precedents in the PPA whereby if the upgrade costs are higher than the thresholds established in the PPA, the contract can be terminated. In the past, developers have had to wait years for study results and in some cases have been faced with extremely high upgrade costs that make their projects unviable. Recent changes in the CAISO's approach for identifying network upgrades that provide interconnecting renewable generators with fully deliverable status appear to be reducing transmission funding hurdles for new generators. However, the process is still under development and SDG&E expects that this area will continue to be potential challenge.

3. Bureau of Land Management ("BLM") Delays

Uncertainty surrounding the availability and timely issuance of Right-of-Way Grants from the BLM creates development risks for project development. The BLM process established to secure land rights has proven to be time-consuming - creating uncertainty, scheduling challenges and corresponding problems with project elements such as financing, permitting, engineering, procurement and construction ("EPC") contracts and supplier contracts.

B. Project Finance, Tax Equity Financing, and Government Incentives

Financing is key for the successful development of renewable projects. Two areas of financing are of primary importance: (i) project financing relied upon to construct the project; and (ii) tax equity financing relied upon to monetize tax benefits such as the Production or Investment Tax Credits. Project Financing has traditionally been provided by financial institutions and costs and availability is a function of the overall health of the financial system. Tax equity financing has also traditionally been provided by banks or large corporations. In order to successfully finance, renewable projects generally need to: (i) complete permitting, (ii) have a long-term fixed price PPA from a credit-worthy offtaker, and (iii) have a bankable (or proven) technology. With the phase out of the Cash Grant and current turmoil in financial markets, non-traditional investors are key to the success of the renewable energy industry. Non-traditional investors include a wider institutional investor reached by projects issuing a security, or utilities and other corporations with tax appetite as tax equity investors.

The extension of the Federal Production Tax Credits ("PTCs") expiring in 2012 and the Investment Tax Credits ("ITCs") expiring in 2016 will be critical to the sustained success of renewable energy in the United States. The PTCs and ITCs currently represent about 33% of the economic value of renewable projects and without them, the relative competitiveness of renewable energy relative to fossil fuels, will be severely impacted.

C. Solar Panel Risk and Project Viability

SDG&E may be subject to industry and technology risks when selecting solar power projects to meet its RPS goals. For example, the industry is undergoing significant consolidation and attrition of market participants. Numerous manufacturers are experiencing severe financial difficulties or have gone bankrupt in response to intense competition and the significant declines in market prices. The risk to SDG&E is that the viability of some low-cost projects may depend on specific manufacturers that might go out of business, forcing the developer to seek other sources. Or, more significantly, the price of panels may increase before the purchase is final and greatly reduce the viability of the project. More industry shakeout is anticipated but prices are expected to stabilize, or increase, once the excess supply is absorbed by the market.

SDG&E also faces technology risks. The company tries to manage technology risks through diversification. For example, photovoltaic panel materials and manufacturing processes vary significantly. There are proven technologies with long operational and performance histories, but there are also newer technologies that have not yet been proven over the typical 20 year contract term. Final technology choices are made by project developers. The risk to the company is that a solar facility may fail to perform as intended due to panel failure or degradation, causing it to fall short of the minimum power delivery requirements. In this case the developer is subject to penalties but, if the failure is too great, the developer may abandon the project. Filing claims under solar panel warranties might be complicated further if the manufacturer is located overseas or is out of business. Such a catastrophic project failure with limited ability to cure through warranty claims could leave a significant short term deficit in the annual RPS goals.

D. Debt Equivalence & Accounting

Two other issues may challenge SDG&E's ability to achieve its RPS goals. The first involves debt equivalence. As SDG&E executes an increasing number of PPAs, the cumulative debt equivalence of all these agreements may greatly affect SDG&E's credit profile and, consequently, its financial standing. Rating agencies include long-term fixed financial obligations, such as power purchase agreements, in their credit risk analysis. These obligations are treated as additional debt during their financial ratio assessment. S&P views the following three ratios, Funds From Operations ("FFO") to Debt, FFO to Interest Expense, and Debt to Capitalization, as the critical components of a utility's credit profile. Debt equivalence negatively impacts all three ratios. Unless mitigated, a PPA would negatively impact SDG&E's credit profile by degrading credit ratios.

The second issue relates to Accounting Standards Codification (ASC) 810 Consolidation, which includes the subject of Consolidation of Variable Interest Entities previously referred to as "FIN 46(R)". Application of ASC 810 as it pertains to Consolidation of Variable Interest Entities (VIEs) could also impact SDG&E's ability to sign new contracts. As part of SDG&E's overall internal review and approval process for new PPAs, SDG&E conducts a review of whether each such PPA will be subject to consolidation under ASC 810. Under ASC 810, no renewable PPA has been deemed subject to such consolidation, however, ASC 810 requires SDG&E to perform an evergreen assessment for those contracts which are considered VIEs. For this reason, SDG&E believes that it is required to assess quarterly each contract or category of contracts to ensure continued compliance with ASC 810, to determine whether or not SDG&E must consolidate a Seller's financial information with SDG&E's own quarterly financial reports to the Securities and Exchange Commission. In particular, wind, solar, geothermal and bio-gas renewable Sellers could be impacted.

Application of ASC 810 could challenge SDG&E's ability to achieve its RPS goals, and add further costs, and risk to execution of new renewable contracts. If SDG&E determines that consolidation is required, a Seller must open its books to SDG&E and submit financial information, on a quarterly and monthly basis, as specified in SDG&E's contract language for the duration of any agreement.

All PPAs are affected by either debt equivalence or ASC 810 requirements. The Commission is well aware of the negative impact of debt equivalence on SDG&E's credit profile. AB 57 requires that the Commission adopt procurement plans that, among other objectives, enhance the creditworthiness of the utility. ASC 810 will affect SDG&E's reported financial data and may have a negative impact on SDG&E's balance sheet and/or credit profile. ASC 810 could impact SDG&E's capital structure on a consolidated basis and cause it to be misaligned with its authorized capital structure.

In order to rebalance to SDG&E's authorized capital structure, SDG&E would be required to infuse additional equity to offset the additional debt. Given that SDG&E will be executing contracts for 20% or more of its overall portfolio to meet its RPS goals, SDG&E anticipates that the Commission will address and mitigate the resulting overall impacts of debt equivalence and ASC 810 to SDG&E's capital structure in the context of SDG&E's recently-filed cost of capital application for test year 2013 filed on June 20, 2012.

E. RPS Cost Containment

The Commission is in the midst of implementing the changes to the RPS Program established by Senate Bill 2 (1X). As a result, full program details are not yet final which creates regulatory uncertainty. Two important outstanding items affecting procurement are RPS cost containment and Compliance proceedings.

An Energy Division staff proposal regarding RPS cost containment is anticipated later this year, with a proposed decision possibly being released in Q1 2013. The decision is expected to implement a cap on the amount of money that retail sellers can spend in an effort to meet RPS goals. Certainty surrounding this potential procurement limit will not be achieved until the final year of Compliance Period 1. This makes it difficult for IOU's to be proactive. It is unclear at this time what the limitation will be for SDG&E, how it will relate to the procurement dollars spent and contracts signed as of the date of the final decision, and how it will interact with the other requirements of the RPS program.

III. PROJECT DEVELOPMENT STATUS UPDATE - § 399.13(A)(5)(D)

As described further in Section I above, SDG&E regularly evaluates project development status to assess each project's ability to begin deliveries in a timely manner. SDG&E's portfolio of renewable energy resources currently under contract but not yet delivering generation are in various stages of development. It is anticipated that projects will enter commercial operation consistently from 2012 to 2015. Projects under development generally require numerous permitting approvals, generator interconnection, financing, and completion of construction before they can achieve commercial operation. Each of the above issues adds significant risk to the development of a project and can directly impact the success or failure of a project. SDG&E's experience is that achieving all of these milestones represents a significant challenge for developers. Although a developer's experience may improve a project's ability to achieve commercial operation, it does not insure that a project will be successful.

SDG&E saw increasing challenges among developers to secure financing after the United States entered the 2008 recession. Subsequently, as more projects were proposed in desert regions, permitting approvals took longer than developers expected due to increased scrutiny of environmental issues and permitting agency coordination efforts. Today, as many projects are obtaining agency permit approvals, there seems to be an increase in litigation challenging the CEQA/NEPA process potentially causing delays while claims are resolved. Throughout this period, the time to study and construct generator interconnection upgrades has grown much longer and significantly more expensive to the developer.

Each project bears significant development risk to resolve all issues necessary to meet commercial operation. SDG&E currently believes that a majority of projects can meet their commercial operation dates either on schedule or within the prescribed cure period. However, SDG&E does have projects that are experiencing possible development issues that could affect their ability to meet commercial operation. SDG&E's need assessment methodology, described in Section I above, takes all of these risks into consideration.

IV. RISK ASSESSMENT - § 399.13(A)(5)(F)

SDG&E also evaluates the risk that delivering projects will underperform. In SDG&E's experience, renewable projects have relatively low risk of non-performance. By achieving commercial operation, developers have made significant investments into the projects and are receiving timely payments for energy delivered. Developers are subject to penalties if they do not meet contractual requirements to supply at least the minimum energy contemplated. However, over the past decade, SDG&E has observed some dynamic factors that may affect power production from delivering projects:

- Resource Availability: For example, a bad wind year can greatly impact a wind facility's performance. Although the contract requires damages for underperformance in an effort to protect ratepayers, a bad wind year can still have an impact on SDG&E's ability to meet its RPS goals, as described in Section I above.

- Regulatory Changes: For example, the expiration of subsidies, such as the Public Goods Charge or the Production Tax Credit, lowers the revenue stream for RPS developers, and can lead to non-production or lower production.

- Economic environment: Specifically, the interest rates and flexibility of financing arrangement entered into by developers can impact the project's success. Long term project financing arrangements with unfavorable terms can lead to project failure or lower production.

- Operational Performance: For example, a facility can experience unexpected mechanical failures that impact performance.

- Evolving technology: Facilities with older generation-technology that is no longer supported by the manufacturer can cause project failure or lower production. This problem is arising now for older RPS projects, and could repeat itself in 20 years when the projects being signed today begin to age.

SDG&E's assessment that current projects are at a low risk of non-performance is based on the above risk factors remaining relatively stable.

V. QUANTITATIVE INFORMATION- §§ 399.13(A)(5)(A), (B), (D), (F)

The following tables provide background data for SDG&E's need assessment as of May 2012.

<u>Table 1-RPS Sensitivity Analysis</u>: this table provides a summary of the impact of some of the key factors that can impact RPS performance.

[redacted]

Table 2 – RPS Banking Analysis: this table provides a detailed analysis of the impact that the determination of whether the Cabazon and Whitewater GAPSAs are considered compliant with the "count in full" requirements of 399.16(d) (*i.e.* are "grandfathered").

Scenario 1 - Cabazon/Whitewater GAPSAs are Grandfathered

	CP1	CP2 - Nominal		CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,318,519	23,184,345		31,451,135	22,638,025
Unbundled RECs* (MWh)				0	0
Short-term Contracts** (MWh)				0	0
Total RPS Bankable Deliveries (MWh)				31,451,135	22,638,025
RPS Target (MWh)				22,212,560	22,212,560
Above or Below Target				Above	Above
Bankable Energy (MWh)				9,238,575	425,465
Banking brought forward from Previous CP (MWh)					
Bankable Energy + Previous CP Bank (MWh)					

Scenario 2- Cabazon/Whitewater GAPSAs are Category 1

	CP1	CP2 - Nominal		CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,318,519	23,184,345		31,451,135	22,638,025
Unbundled RECs* (MWh)				0	0
Short-term Contracts** (MWh)				0	0
Total RPS Bankable Deliveries (MWh)				31,451,135	22,638,025
RPS Target (MWh)				22,212,560	22,212,560
Above or Below Target				Above	Above
Bankable Energy (MWh)				9,238,575	425,465
Banking brought forward from Previous CP (MWh)					
Bankable Energy + Previous CP Bank (MWh)					

Table 3 - Impact of Potential Deficit From Prior Compliance Regime:

RPS Procurement and Targets (MWh)	2003	2004	2005	2006	2007	2008	2009	2010
Bundled Retail Sales	15,043,865	15,811,591	16,001,516	16,846,888	17,056,023	17,409,884	16,993,872	16,282,682
Total RPS Eligible Procurement	549,856	677,852	825,302	899,520	880,777	1,047,441	1,784,441	1,940,129
Annual Procurement Target (APT)	296,073	446,511	604,627	764,642	933,111	1,103,671	1,277,770	3,256,536
Incremental Procurement Target (IPT)	N/A	150,439	158,116	160,015	168,469	170,560	174,099	1,978,766
Preliminary Procurement Surplus/(Deficit)	253,783	231,341	220,675	134,878	(52,334)	(56,231)	506,670	(1,316,408)

2010 Actual Procurement Percentage	2003	2004	2005	2006	2007	2008	2009	2010
Surplus Procurement Bank Balance as of Prior Year	0	253,783	485,124	705,798	840,677	788,342	732,112	1,238,782
Application of Banked Surplus Procurement to Current Year Deficit					(52,334)	(56,231)		(1,316,408)
Adjusted Current Year Annual Surplus Procurement	253,783	231,341	220,675	134,878	0	0	506,670	0
Cumulative Surplus/(Deficit) Procurement Bank Balance Carried into CP1	253,783	485,124	705,798	840,677	788,342	732,112	1,238,782	(77,625)

Renewable Net Short Calculation:

The tables below provide the data behind SDG&E's RPS Risk Adjusted Net Short Calculation as of August, 2012 and includes the outputs required by Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans, dated August 2, 2012. A discussion of this analysis is provided in Section VI below.

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2011 Actuals	2012 Expected	2013 Forecast	CP1 **2011-2013**	2014 Forecast	2015 Forecast	**2016 Forecast**	CP2 **2014-2016**
T		Forecast Year			1		2	3	4	
A		**Bundled Retail Sales Forecast[1]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	18,074	[redacted]
B		**RPS Procurement Quantity Requirement %**	20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	
C		**RPS Procurement Quantity Requirement**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4,519	[redacted]
D_a		*Risk-Adjusted Online Generation[2]*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*1,532*	[redacted]
D_b		*Risk-Adjusted Forecast Generation[2]*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*3,812*	[redacted]
D_c		*Pre-Approved Generic Generation[2]*	-	-	2	2	*138*	*306*	*483*	927
D	$D_a + D_b + D_c$	**Net RPS Position[5]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
E	D / A	Net RPS Position (% of Retail Sales)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	32.2%	[redacted]
F	D - C	**GWh Gross Surplus (Deficit)**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
G		Banked RECs applied	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
I		All RECs from short-term contracts signed after 6/1/10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]
J		*Limit of Category 3 allowed under statute*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*515*	[redacted]
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
M	L - C	**Excess Procurement for CP**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
N	Max $(M_{(T-1)},0) + M_T$	**REC Bank Balance**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3,966	[redacted]
		Aggregated probability weighted GWh data[3]								
O_a		*High viability (>=85%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*2,998*	[redacted]
O_b		*Viable (70-85%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*911*	[redacted]
O_c		*High Risk (<70%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	*1,917*	[redacted]
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
P		Aggregate delivery failure rate - new projects[4]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	37.4%	[redacted]
Q		Aggregate delivery failure rate - existing projects[4]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8.1%	[redacted]
R	A x 1.5%	Voluntary Margin of Overprocurement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
S		Voluntary Margin of Overprocurement (implied % of retail sales)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.2%	[redacted]
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5% ; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5) CP1 total includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2017 Forecast	2018 Forecast	2019 Forecast	**2020 Forecast**	CP3 **2017-2020**	2021 Forecast	2022 Forecast	2023 Forecast
T		Forecast Year	5	6	7	8		9	10	11
A		**Bundled Retail Sales Forecast(1)**	**18,216**	**18,375**	**18,578**	**18,807**	**73,976**	**19,014**	**19,223**	**19,434**
B		**RPS Procurement Quantity Requirement %**	**27.0%**	**29.0%**	**31.0%**	**33.0%**		**33.0%**	**33.0%**	**33.0%**
C		**RPS Procurement Quantity Requirement**	**4,918**	**5,329**	**5,759**	**6,206**	**22,213**	**6,275**	**6,344**	**6,413**
D_a		*Risk-Adjusted Online Generation(2)*	*1,496*	*1,167*	*1,058*	*890*	***4,611***	*963*	*963*	*868*
D_b		*Risk-Adjusted Forecast Generation(2)*	*3,799*	*3,787*	*3,772*	*3,759*	***15,118***	*3,758*	*3,751*	*3,745*
D_c		*Pre-Approved Generic Generation(2)*	*545*	*545*	*545*	*546*	***2,181***	*546*	*546*	*546*
D	$D_a + D_b + D_c$	**Net RPS Position**	**5,840**	**5,500**	**5,375**	**5,195**	**21,910**	**5,266**	**5,260**	**5,159**
E	D / A	Net RPS Position (% of Retail Sales)	32.1%	29.9%	28.9%	27.6%	29.6%	27.7%	27.4%	26.5%
F	D - C	**GWh Gross Surplus (Deficit)**	**921**	**171**	**(384)**	**(1,011)**	**(303)**	**(1,009)**	**(1,084)**	**(1,254)**
G		Banked RECs applied	-	-	384	1,011	**1,395**	1,009	1,084	1,254
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	**921**	**171**	**0**	**(0)**	**1,092**	**0**	**0**	**(0)**
I		All RECs from short-term contracts signed after 6/1/10	-	-	-	-	-	-	-	-
J		*Limit of Category 3 allowed under statute*	*349*	*347*	*346*	*345*	***1,387***	*344*	*344*	*343*
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	**5,840**	**5,500**	**5,375**	**5,195**	**21,910**	**5,178**	**5,172**	**5,076**
M	L - C	**Excess Procurement for CP**	**921**	**171**	**(384)**	**(1,011)**	**(303)**	**(1,096)**	**(1,171)**	**(1,337)**
N	$Max (M_{(T-1)},0) + M_T$	**REC Bank Balance**	**4,888**	**5,059**	**4,675**	**3,664**	**3,664**	**2,655**	**1,571**	**317**
		Aggregated probability weighted GWh data(3)								
O_a		*High viability (>=85%)*	*3,021*	*2,689*	*2,576*	*2,569*		*2,570*	*2,473*	*2,178*
O_b		*Viable (70-85%)*	*909*	*907*	*904*	*738*		*721*	*717*	*714*
O_c		*High Risk (<70%)*	*1,910*	*1,904*	*1,895*	*1,888*		*1,887*	*1,886*	*1,886*
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	5,840	5,500	5,375	5,195	-	5,178	5,076	4,778
P		Aggregate delivery failure rate - new projects(4)	37.4%	37.4%	37.3%	37.3%	37.4%	37.3%	37.3%	37.3%
Q		Aggregate delivery failure rate - existing projects(4)	7.9%	7.5%	7.7%	5.2%	7.2%	5.0%	5.0%	5.0%
R	A x 1.5%	Voluntary Margin of Overprocurement	921	171	0	-	1,093	0	0	-
S		Voluntary Margin of Overprocurement (implied % of retail sales)	5.1%	0.9%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	**0**	**-**	**384**	**1,011**	**1,395**	**1,097**	**1,268**	**1,636**

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5% ; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5)Includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
T		Forecast Year	12	13	14	15	16	17	18	19
A		**Bundled Retail Sales Forecast(1)**	**19,648**	**19,864**	**20,083**	**20,304**	**20,527**	**20,753**	**20,981**	**21,212**
B		**RPS Procurement Quantity Requirement %**	**33.0%**	**33.0%**	**33.0%**	**33.0%**	**33.0%**	**33.0%**	**33.0%**	**33.0%**
C		**RPS Procurement Quantity Requirement**	**6,484**	**6,555**	**6,627**	**6,700**	**6,774**	**6,848**	**6,924**	**7,000**
D_a		*Risk-Adjusted Online Generation(2)*	*543*	*232*	*40*	*38*	*38*	*38*	*38*	*18*
D_b		*Risk-Adjusted Forecast Generation(2)*	*3,739*	*3,733*	*3,727*	*3,721*	*3,715*	*3,709*	*3,703*	*3,697*
D_c		*Pre-Approved Generic Generation(2)*	*546*	*534*	*534*	*534*	*534*	*535*	*535*	*535*
D	$D_a + D_b + D_c$	**Net RPS Position**	**4,828**	**4,499**	**4,301**	**4,293**	**4,287**	**4,282**	**4,276**	**4,250**
E	D / A	Net RPS Position (% of Retail Sales)	24.6%	22.6%	21.4%	21.1%	20.9%	20.6%	20.4%	20.0%
F	D - C	**GWh Gross Surplus (Deficit)**	**(1,656)**	**(2,057)**	**(2,326)**	**(2,407)**	**(2,487)**	**(2,567)**	**(2,648)**	**(2,750)**
G		Banked RECs applied	317	-	-	-	-	-	-	-
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	**(1,339)**	**(2,057)**	**(2,326)**	**(2,407)**	**(2,487)**	**(2,567)**	**(2,648)**	**(2,750)**
I		All RECs from short-term contracts signed after 6/1/10	-	-	-	-	-	-	-	-
J		*Limit of Category 3 allowed under statute*	*343*	*341*	*338*	*338*	*337*	*337*	*336*	*336*
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	**4,778**	**4,479**	**4,300**	**4,292**	**4,286**	**4,280**	**4,275**	**4,250**
M	L - C	**Excess Procurement for CP**	**(1,706)**	**(2,076)**	**(2,328)**	**(2,408)**	**(2,488)**	**(2,568)**	**(2,649)**	**(2,750)**
N	$\text{Max}(M_{(T-1)},0) + M_T$	**REC Bank Balance**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
		Aggregated probability weighted GWh data(3)								
O_a		*High viability (>=85%)*	*1,882*	*1,705*	*1,700*	*1,697*	*1,694*	*1,691*	*1,668*	*1,354*
O_b		*Viable (70-85%)*	*712*	*710*	*708*	*705*	*703*	*701*	*699*	*697*
O_c		*High Risk (<70%)*	*1,885*	*1,885*	*1,884*	*1,884*	*1,883*	*1,883*	*1,882*	*1,800*
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	4,479	4,300	4,292	4,286	4,280	4,275	4,250	3,851
P		Aggregate delivery failure rate - new projects(4)	37.3%	37.3%	37.3%	37.3%	37.3%	37.4%	37.4%	37.4%
Q		Aggregate delivery failure rate - existing projects(4)	3.5%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%
R	A x 1.5%	Voluntary Margin of Overprocurement	-	-	-	-	-	-	-	-
S		Voluntary Margin of Overprocurement (implied % of retail sales)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	**2,005**	**2,256**	**2,336**	**2,414**	**2,494**	**2,574**	**2,674**	**3,149**

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5% ; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5)Includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

Contracts Presently Delivering - August 13, 2012										Probability Weighted Deliveries									
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Shell			Wind	9/10/09	1.75	4/1/10	12/31/11	104.4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Otay Landfill 1	[redacted]	[redacted]	Biogas	5/1/09	10	5/1/09	4/30/19	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Otay Landfill II	[redacted]	[redacted]	Biogas	2/22/11	20	7/1/11	6/30/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	San Marcos Landfill	[redacted]	[redacted]	Biogas	11/20/09	20	5/18/11	5/17/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Sycamore Landfill	[redacted]	[redacted]	Biogas	11/20/09	20	5/16/11	5/15/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Badger Filtration Plant	[redacted]	[redacted]	Conduit Hydro	2/28/85	30	7/1/87	6/30/17	1.485	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Bear Valley Hydro	[redacted]	[redacted]	Conduit Hydro	4/13/94	Evergreen	4/13/94	Evergreen	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Olivenhain Municipal	[redacted]	[redacted]	Conduit Hydro	9/16/87	Evergreen	11/1/88	Evergreen	0.45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	San Francisco Peak Hydro Plant	[redacted]	[redacted]	Conduit Hydro	8/29/85	Evergreen	12/15/85	Evergreen	0.35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	MM San Diego - Miramar	[redacted]	[redacted]	Biogas	10/31/02	10	5/20/03	4/30/13	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	MM San Diego - North City	[redacted]	[redacted]	Biogas	10/31/02	10	5/20/03	4/30/13	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	GRS - Coyote Canyon	[redacted]	[redacted]	Biogas	10/31/02	10	1/1/03	12/31/12	6.057	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	GRS - Sycamore	[redacted]	[redacted]	Biogas	10/31/02	10	3/30/04	3/30/14	2.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	MM Prima Deshecha	[redacted]	[redacted]	Biogas	9/6/05	15	10/1/07	9/30/22	12.2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Otay Lanfill 3	[redacted]	[redacted]	Biogas	8/31/05	10	3/8/07	3/7/17	3.375	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Blue Lake Power	[redacted]	[redacted]	Biomass	6/9/08	10	4/30/10	4/29/20	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	City of San Diego MWD	[redacted]	[redacted]	Biogas	12/22/06	5	1/1/08	12/31/12	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Covanta Delano	[redacted]	[redacted]	Biomass	12/21/06	10	1/1/08	12/31/17	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Kumeyaay	[redacted]	[redacted]	Wind	5/31/04	20	3/21/06	12/30/25	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Oasis Power Partners	[redacted]	[redacted]	Wind	10/30/02	15	12/31/04	12/30/19	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Iberdrola Mt Wind	[redacted]	[redacted]	Wind	11/1/02	16	12/15/03	12/31/18	22.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Iberdrola PWest	[redacted]	[redacted]	Wind	11/1/02	16	12/15/03	12/31/18	2.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	WTE Acquisition (FPL)	[redacted]	[redacted]	Wind	10/31/02	15	6/28/04	12/31/18	16.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Glacier Wind 1	[redacted]	[redacted]	Wind	5/16/08	15	12/29/08	12/29/23	106.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Glacier Wind 2	[redacted]	[redacted]	Wind	5/23/08	15	10/16/09	10/16/24	103.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Coram	[redacted]	[redacted]	Wind	7/15/10	15	2/1/11	1/31/26	7.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	SDCWA - Rancho Penasquitos	[redacted]	[redacted]	Conduit Hydro	11/20/03	10	1/23/07	1/22/17	4.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	SDG&E Sustainable Communities	[redacted]	[redacted]	Solar PV	5/30/10	30	5/4/09	5/4/39	0.54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	Calpine - Geysers	[redacted]	[redacted]	Geothermal	2/26/10	4.833	3/1/10	12/31/14	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Silicon Valley	[redacted]	[redacted]	Geothermal	6/30/11	1	7/1/11	6/30/12	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Calpine - Geysers	[redacted]	[redacted]	Geothermal	9/22/11	0.25	10/1/11	12/31/11	11.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Edison	[redacted]	[redacted]	Various	9/22/11	2.3	10/1/11	12/31/13	193	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	Mesa	[redacted]	[redacted]	Wind	11/2/11	2	4/1/12	12/31/13	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	SDG&E SEP (UOG)	[redacted]	[redacted]	Solar PV	7/11/08	30	1/1/10	1/1/40	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	RAM (To be added)	[redacted]	[redacted]	Solar PV		30	1/1/09	1/1/39	125	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	FIT (To be added)	[redacted]	[redacted]	Various		20	6/1/12	5/31/32	39.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	Edison 2	[redacted]	[redacted]	Various	3/23/12	0.3	9/1/12	12/31/12	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	Sierra Pacific Industries	[redacted]	[redacted]	Biomass	3/30/12	0			0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Cabazon	[redacted]	[redacted]	Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	Whitewater	[redacted]	[redacted]	Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

										Probability Weighted Deliveries										
Contracts Presently Delivering August 13, 2012																				
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Shell	[redacted]	[redacted]	Wind	9/10/09	1.75	4/1/10	12/31/11	104.4	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Otay Landfill I	[redacted]	[redacted]	Biogas	5/1/09	10	5/1/09	4/30/19	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Otay Landfill II	[redacted]	[redacted]	Biogas	2/22/11	20	7/1/11	6/30/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	San Marcos Landfill	[redacted]	[redacted]	Biogas	11/20/09	20	5/18/11	5/17/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Sycamore Landfill	[redacted]	[redacted]	Biogas	11/20/09	20	5/16/11	5/15/31	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Badger Filtration Plant	[redacted]	[redacted]	Conduit Hydro	2/28/85	30	7/1/87	6/30/17	1.485	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	Bear Valley Hydro	[redacted]	[redacted]	Conduit Hydro	4/13/94	Evergreen	4/13/94	Evergreen	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Olivenhain Municipal	[redacted]	[redacted]	Conduit Hydro	9/16/87	Evergreen	11/1/88	Evergreen	0.45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	San Francisco Peak Hydro Plant	[redacted]	[redacted]	Conduit Hydro	8/29/85	Evergreen	12/15/85	Evergreen	0.35	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	MM San Diego Miramar	[redacted]	[redacted]	Biogas	10/31/02	10	5/20/03	4/30/13	3	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	MM San Diego North City	[redacted]	[redacted]	Biogas	10/31/02	10	5/20/03	4/30/13	1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	GRS Coyote Canyon	[redacted]	[redacted]	Biogas	10/31/02	10	1/1/03	12/31/12	6.057	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	GRS Sycamore	[redacted]	[redacted]	Biogas	10/31/02	10	3/30/04	3/30/14	2.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	MM Prima Deshecha	[redacted]	[redacted]	Biogas	9/6/05	15	10/1/07	9/30/22	12.2	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Otay Lanfill 3	[redacted]	[redacted]	Biogas	8/31/05	10	3/8/07	3/7/17	3.375	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Blue Lake Power	[redacted]	[redacted]	Biomass	6/9/08	10	4/30/10	4/29/20	11	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	City of San Diego MWD	[redacted]	[redacted]	Biogas	12/22/06	5	1/1/08	12/31/12	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Covanta Delano	[redacted]	[redacted]	Biomass	12/21/06	10	1/1/08	12/31/17	49	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Kumeyaay	[redacted]	[redacted]	Wind	5/31/04	20	3/21/06	12/30/25	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Oasis Power Partners	[redacted]	[redacted]	Wind	10/30/02	15	12/31/04	12/30/19	60	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Iberdrola Mt Wind	[redacted]	[redacted]	Wind	11/1/02	16	12/15/03	12/31/18	22.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Iberdrola PWest	[redacted]	[redacted]	Wind	11/1/02	16	12/15/03	12/31/18	2.1	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	WTE Acquisition (FPL)	[redacted]	[redacted]	Wind	10/31/02	15	6/28/04	12/31/18	16.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Glacier Wind 1	[redacted]	[redacted]	Wind	5/16/08	15	12/29/08	12/29/23	106.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	Glacier Wind 2	[redacted]	[redacted]	Wind	5/23/08	15	10/16/09	10/16/24	103.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Coram	[redacted]	[redacted]	Wind	7/15/10	15	2/1/11	1/31/26	7.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	SDCWA Rancho Penasquitos	[redacted]	[redacted]	Conduit Hydro	11/20/03	10	1/23/07	1/22/17	4.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	SDG&E Sustainable Communitie	[redacted]	[redacted]	Solar PV	5/30/10	30	5/4/09	5/4/39	0.54	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	Calpine Geysers	[redacted]	[redacted]	Geothermal	2/26/10	4.833	3/1/10	12/31/14	25	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	Silicon Valley	[redacted]	[redacted]	Geothermal	6/30/11	1	7/1/11	6/30/12	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Calpine Geysers	[redacted]	[redacted]	Geothermal	9/22/11	0.25	10/1/11	12/31/11	11.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
32	Edison	[redacted]	[redacted]	Various	9/22/11	2.3	10/1/11	12/31/13	193	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
33	Mesa	[redacted]	[redacted]	Wind	11/2/11	2	4/1/12	12/31/13	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
34	SDG&E SEP (UOG)	[redacted]	[redacted]	Solar PV	7/11/08	30	1/1/10	1/1/40	17	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
35	RAM (To be added)	[redacted]	[redacted]	Solar PV		30	1/1/09	1/1/39	125	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
36	FIT (To be added)	[redacted]	[redacted]	Various		20	6/1/12	5/31/32	39.8	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
37	Edison 2	[redacted]	[redacted]	Various	3/23/12	0.3	9/1/12	12/31/12	103	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
38	Sierra Pacific Industries	[redacted]	[redacted]	Biomass	3/30/12	0			0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
39	Cabazon	[redacted]	[redacted]	Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
40	Whitewater	[redacted]	[redacted]	Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Contracts Presently Developing August 13, 2012											Probability Weighted Deliveries									
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Centinela	[redacted]		Solar PV	5/10/10	20	4/1/14	3/31/34	125		[redacted]									
2	Centinela 2	[redacted]		Solar PV	7/29/10	20	9/1/14	8/31/34	30		[redacted]									
3	Rim Rock	[redacted]		Wind	5/5/09	20	10/1/12	9/30/32	189		[redacted]									
4	Pattern	[redacted]		Wind	2/1/11	20	12/15/12	12/15/33	265		[redacted]									
5	Pacific Wind	[redacted]		Wind	10/14/05	20	8/31/12	8/30/32	140		[redacted]									
6	Solargen2	[redacted]		Solar PV	6/24/11	25	9/30/12	9/29/37	150		[redacted]									
7	enXco Catalina	[redacted]		Solar PV	6/3/11	25	6/30/13	6/30/38	110		[redacted]									
8	Alta Mesa	[redacted]		Wind	12/17/09	20	3/1/12	2/28/32	40		[redacted]									
9	Arlington	[redacted]		Solar PV	6/3/11	25	12/20/13	12/19/38	127		[redacted]									
10	ESJ	[redacted]		Wind	4/6/11	20	8/31/13	12/31/33	150		[redacted]									
11	NRG Borrego	[redacted]		Solar PV	1/25/11	25	7/31/12	7/31/37	26		[redacted]									
12	Sol Orchard	[redacted]		Solar PV	4/11/11	25	12/31/12	12/30/37	50		[redacted]									
13	MMR Campo Verde	[redacted]		Solar PV	11/10/06	20	9/30/13	9/29/33	139		[redacted]									
14	Tenaska South	[redacted]		Solar PV	11/10/10	25	1/1/14	1/1/39	130		[redacted]									
15	Victor Mesa Linda B	[redacted]		Solar PV		20	10/31/13	10/31/33	5		[redacted]									
16	Western Antelope Dry Ranch	[redacted]		Solar PV		20	10/31/13	10/31/33	10		[redacted]									
17	Soitec TDS	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	45		[redacted]									
18	Soitec Rugged	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	80		[redacted]									
19	Campo (Shuu'luk)	[redacted]		Wind		25	10/1/14	9/30/39	160		[redacted]									
20	Tenaska West	[redacted]		Solar PV	3/8/11	25	1/1/16	12/31/40	140		[redacted]									
21	Soitec Desert Green	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5		[redacted]									
22	Soitec Eastland	[redacted]		Solar PV	3/31/11	25	10/31/14	10/30/39	20		[redacted]									
23	Soitec Westland	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5		[redacted]									
24	Manzana	[redacted]		Wind	2/14/12	20	10/31/12	6/30/32	100		[redacted]									
25	AES Mt Signal 1 Solar	[redacted]		Solar PV	2/10/12	25	5/31/13	6/29/38	200		[redacted]									
26	Otay Landfill V CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5		[redacted]									
27	Otay Landfill VI CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5		[redacted]									
28	Otay Landfill VII CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5		[redacted]									
29	Mushroom Power CRE (FIT)	[redacted]		Biomass	12/12/11	20	10/1/12	9/30/32	1.5		[redacted]									
30	BAP Power CRE (FIT)	[redacted]		Solar PV	12/13/11	20	9/1/12	8/31/32	1.5		[redacted]									
31	Descanso Solar CRE (FIT)	[redacted]		Solar PV	12/27/11	20	7/15/13	7/14/33	1.5		[redacted]									

Contracts Presently Developing August 13, 2012										Probability Weighted Deliveries										
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Centinela	[redacted]		Solar PV	5/10/10	20	4/1/14	3/31/34	125	[redacted]										
2	Centinela 2	[redacted]		Solar PV	7/29/10	20	9/1/14	8/31/34	30	[redacted]										
3	Rim Rock	[redacted]		Wind	5/5/09	20	10/1/12	9/30/32	189	[redacted]										
4	Pattern	[redacted]		Wind	2/1/11	20	12/15/12	12/15/33	265	[redacted]										
5	Pacific Wind	[redacted]		Wind	10/14/05	20	8/31/12	8/30/32	140	[redacted]										
6	Solargen2	[redacted]		Solar PV	6/24/11	25	9/30/12	9/29/37	150	[redacted]										
7	enXco Catalina	[redacted]		Solar PV	6/3/11	25	6/30/13	6/30/38	110	[redacted]										
8	Alta Mesa	[redacted]		Wind	12/17/09	20	3/1/12	2/28/32	40	[redacted]										
9	Arlington	[redacted]		Solar PV	6/3/11	25	12/20/13	12/19/38	127	[redacted]										
10	ESJ	[redacted]		Wind	4/6/11	20	8/31/13	12/31/33	150	[redacted]										
11	NRG Borrego	[redacted]		Solar PV	1/25/11	25	7/31/12	7/31/37	26	[redacted]										
12	Sol Orchard	[redacted]		Solar PV	4/11/11	25	12/31/12	12/30/37	50	[redacted]										
13	MMR Campo Verde	[redacted]		Solar PV	11/10/06	20	9/30/13	9/29/33	139	[redacted]										
14	Tenaska South	[redacted]		Solar PV	11/10/10	25	1/1/14	1/1/39	130	[redacted]										
15	Victor Mesa Linda B	[redacted]		Solar PV		20	10/31/13	10/31/33	5	[redacted]										
16	Western Antelope Dry Ranch	[redacted]		Solar PV		20	10/31/13	10/31/33	10	[redacted]										
17	Soitec TDS	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	45	[redacted]										
18	Soitec Rugged	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	80	[redacted]										
19	Campo (Shuu'luk)	[redacted]		Wind		25	10/1/14	9/30/39	160	[redacted]										
20	Tenaska West	[redacted]		Solar PV	3/8/11	25	1/1/16	12/31/40	140	[redacted]										
21	Soitec Desert Green	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]										
22	Soitec Eastland	[redacted]		Solar PV	3/31/11	25	10/31/14	10/30/39	20	[redacted]										
23	Soitec Westland	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]										
24	Manzana	[redacted]		Wind	2/14/12	20	10/31/12	6/30/32	100	[redacted]										
25	AES Mt Signal 1 Solar	[redacted]		Solar PV	2/10/12	25	5/31/13	6/29/38	200	[redacted]										
26	Otay Landfill V CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]										
27	Otay Landfill VI CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]										
28	Otay Landfill VII CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]										
29	Mushroom Power CRE (FIT)	[redacted]		Biomass	12/12/11	20	10/1/12	9/30/32	1.5	[redacted]										
30	BAP Power CRE (FIT)	[redacted]		Solar PV	12/13/11	20	9/1/12	8/31/32	1.5	[redacted]										
31	Descanso Solar CRE (FIT)	[redacted]		Solar PV	12/27/11	20	7/15/13	7/14/33	1.5	[redacted]										

VI. "MINIMUM MARGIN" OF PROCUREMENT- -§ 399.13(A)(4)(D)

SDG&E's RPS Risk Adjusted Net Short Calculation, as shown in Section V above, provides a "Minimum Margin of Procurement" that is intended to account for foreseeable project failures or delay. This calculation also includes an additional "Voluntary Margin of Over-Procurement", which is intended to ensure that SDG&E achieves its RPS requirements despite unforeseeable risks. Since both the RPS targets and RPS deliveries fluctuate constantly, it is nearly impossible to meet RPS targets with the exact number of MWhs required. SDG&E's Voluntary Margin of Over-Procurement is designed to ensure that it achieves its RPS goals with a "buffer" to account for unforeseen changes to either the RPS targets or deliveries. Because it is more difficult to predict retail sales and project performance in CP2 and CP3, SDG&E's Voluntary Margin of Over-Procurement is higher in those years. SDG&E's RNS calculation, including its Voluntary Margin of Over-Procurement, for each compliance period is described below.

A. Compliance Period 1

SDG&E's Compliance Period 1 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 1 RPS percentage target plus the deficit that SDG&E is required to carry forward from the prior RPS regime as discussed in Section I(B)(2)(g) of SDG&E's 2012 RPS Plan.
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP1
- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan
- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

B. Compliance Period 2

SDG&E's Compliance Period 2 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 2 RPS percentage target
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP2
- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan
- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

C. Compliance Period 3

SDG&E's Compliance Period 3 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 3 RPS percentage target
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP3

- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan
- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

VII. BID SOLICITATION PROTOCOL, INCLUDING LCBF METHODOLOGIES - § 399.13(A)(5)(C) AND D.04-07-029

Attached are SDG&E's proposed bid solicitation protocol and related documents for a 2012 RPS solicitation (2012 RPS RFO).

- Appendix A: 2012 RPS Solicitation (RFO Document)
- Appendix B1: 2012 RFO Participation Summary
- Appendix B2: 2012 RFO Project Description Form
- Appendix B3: 2012 RFO Bundled Pricing Form
- Appendix B4: 2012 RFO REC Pricing Form
- Appendix B5: 2012 RFO Model PPA
- Appendix B6: 2012 RFO REC Agreement
- Appendix B7: 2012 RFO Credit Application
- Appendix B8: 2012 RFO Consent Form
- Appendix C: Evaluation Methodology (LCBF Process)

VIII. ESTIMATING TRANSMISSION COST FOR THE PURPOSE OF RPS PROCUREMENT AND BID EVALUATION - TRANSMISSION RANKING COST REPORT REQUIRED

SDG&E filed a draft TRCR on June 26, 2012.

IX. CONSIDERATION OF PRICE ADJUSTMENT MECHANISMS -§ 399.13(A)(5)(E)

SDG&E acknowledges that contracts with online dates occurring more than 24 months after the contract execution date can pose additional risk to ratepayers. SDG&E has incorporated price adjustment mechanisms in some of its current contracts that are intended to alleviate some of these risks, including the following:

- Price adjustment for delay in Guaranteed Commercial Operation Date ("GCOD"): A lower price for a late GCOD provides additional incentive for developers to come online as early as possible. However, this structure can create financing challenges if financing parties are not comfortable with the potentially lower price. It is also difficult to quantify an appropriate price adjustment amount and can lead to drawn out negotiations.
- Capped transmission upgrade costs: Placing a cap on the amount of transmission upgrade costs, which are ultimately borne by ratepayers, that a project can bear is an important way to limit ratepayer exposure to such costs. This type of cap is especially important for projects with CODs more than 24 months after the contract execution date because it is unlikely that such projects have received reliable transmission upgrade cost estimates at the time the contract is signed.

SDG&E also proposes a revised security provision that is intended to alleviate the risk of a long period between execution and construction. The Construction Period Security should escalate in proportion to the duration of time between contract execution and start of construction. For example:

- For Projects with a construction start date within 12 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $20
- For Projects with a construction start date within 24 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $30
- For Projects with a construction start date within 36 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $40

SDG&E believes that this security structure will help to protect ratepayers from the risk that developers have improperly assessed turbine or panel prices. The longer the developer must wait to buy turbines/panels, the more risk exists that the prices will go up and the developer will not be able to develop the project for the price offered. The additional security would help to protect against this increased market risk.

X. COST QUANTIFICATION TABLE

		Actual RPS Eligible Procurement and Generation Costs								
1	Technology Type	2003	2004	2005	2006	2007	2008	2009	2010	2011
2	Biogas	6,201,139	8,541,291	8,915,866	8,087,169	6,685,347	9,388,536	10,067,817	11,383,663	10,699,119
3	Biomass	18,888,387	18,693,045	17,205,462	16,965,465	12,237,997	22,995,311	24,605,914	27,430,655	27,275,365
4	Geothermal	0	0	0	0	0	0	0	14,679,414	29,437,292
5	Small Hydro	0	0	0	0	994,116	1,210,445	1,035,376	1,036,066	776,149
6	Solar PV	0	0	0	0	0	0	0	0	8,411,735
7	Solar Thermal	0	0	0	0	0	0	0	0	0
8	Wind	22,750	5,980,963	14,097,259	19,779,696	22,968,510	22,131,340	60,255,477	54,744,756	66,266,623
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0
11	RECs (incl. any buy/sell back	0	0	0	0	0	0	0	0	0
12	**Total CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 2 through 11]	**25,112,276**	**33,215,299**	**40,218,587**	**44,832,330**	**42,885,970**	**55,725,632**	**95,964,584**	**109,274,554**	**142,866,283**
13	Bundled Retail Sales (kWh	15,043,865,000	15,811,591,000	16,001,516,000	16,846,888,000	17,056,023,000	17,409,884,000	16,993,872,000	16,282,682,000	16,249,031,000
14	**Incremental Cost per kWh (cents/kWh)**	0.167	0.210	0.251	0.266	0.251	0.320	0.565	0.671	0.879

* Incremental Cost per kWh Impact is equal to Row 12 divided by Row 13, that is, it is defined as the identified costs (Row 12) divided by bundled retail sales (Row 13). While the item is labeled "Incremental Cost per kWh Impact", the value does not constitute a rate impact and should be interpreted as an estimate of a system average cost per kWh for RPS-eligible procurement and generation, not a renewable "premium". In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

		Forecasted Future Expenditures on RPS Eligible Procurement and Generation Costs								
1	**Executed But Not CPUC Approved RPS Eligible Contracts**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
2	Biogas	0	0	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0	0	0
4	Geotherma	22,800,000	0	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0	0	0
6	Solar PV	33,809,910	94,656,947	110,616,543	109,831,204	108,681,105	107,740,489	107,181,999	105,901,966	105,005,713
7	Solar Thermal	0	0	0	0	0	0	0	0	0
8	Wind	14,140,000	28,765,000	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0
11	RECs (incl. any buy/sell back	280,500	0	0	0	0	0	0	0	0
12	**Total Executed But Not CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 2 through 11]	**71,030,410**	**123,421,947**	**148,428,187**	**147,642,848**	**146,492,749**	**145,552,133**	**144,993,643**	**143,713,610**	**142,817,356**
13	Bundled Retail Sales (kWh	[redacted]	[redacted]	[redacted]	[redacted]	18,595,626,000	18,873,220,000	19,154,172,000	19,454,994,000	19,759,758,000
14	**Incremental Cost per kWh (cents/kWh)**	[redacted]	[redacted]	[redacted]	[redacted]	0.788	0.771	0.757	0.739	0.723
15	**CPUC Approved RPS Eligible Contracts (Incl. RAM/FIT/PV Contracts)**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
16	Biogas	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750
17	Biomass	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321
18	Geothermal	52,128,755	52,128,755	24,217,020	0	0	0	0	0	0
19	Small Hydro	994,116	994,116	994,116	994,116	994,116	994,116	994,116	994,116	994,116
20	Solar PV	34,764,385	97,039,334	240,827,532	296,677,387	356,497,175	355,897,471	355,306,603	354,724,559	354,151,239
21	Solar Thermal	0	0	0	0	0	0	0	0	0
22	Wind	60,751,078	97,495,476	240,312,652	242,204,900	243,761,852	245,558,959	247,769,662	249,291,509	251,294,499
23	UOG Small Hydro	0	0	0	0	0	0	0	0	0
24	UOG Solar	0	0	0	0	0	0	0	0	0
25	RECs (incl. any buy/sell back	0	0	0	0	0	0	0	0	0
26	**CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 16 through 25]	**185,214,405**	**284,233,752**	**542,927,391**	**576,452,474**	**637,829,213**	**639,026,617**	**640,646,452**	**641,586,254**	**643,015,925**
27	Bundled Retail Sales (kWh	[redacted]	[redacted]	[redacted]	[redacted]	18,595,626,000	18,873,220,000	19,154,172,000	19,454,994,000	19,759,758,000
28	**Incremental Cost per kWh (cents/kWh)**	[redacted]	[redacted]	[redacted]	[redacted]	3.430	3.386	3.345	3.298	3.254
29	**Total Cost per kWh (cents/kWh) (14+28)**	[redacted]	[redacted]	[redacted]	[redacted]	4.218	4.157	4.102	4.036	3.977

* Incremental Cost per kWh Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Cost per kWh Impact", the value does not constitute a rate impact and should be interpreted as an estimate of a system averagecost per kWh for RPS-eligible procurement and generation, not a renewable "premium". In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

XI. IMPORTANT CHANGES TO PLANS NOTED

See Appendix D: Important Plan Changes from 2012 RPS Plan to the 2011 RPS Plan

XII. REDLINED COPY OF PLANS REQUIRED

See Appendix E: Provides redlined version of each of the documents above to show all changes that have been made to the 2011 version of the RPS Plan.

XIII. STANDARDIZED VARIABLES IN LCBF MARKET VALUATION

The proposed Net Market Value calculation differs only slightly from SDG&E's current bid evaluation methodology and SDG&E is not opposed to incorporating the proposed method. The most important issue will be determining what value to use for the Capacity Value. SGD&E submits that the Market Price Referent is the most appropriate value to use.

A renewable energy resource is assigned a capacity value based upon the amount of new generating capacity that would otherwise have to be built to meet SDG&E's needs if the renewable energy resource were not built or would not otherwise displace the need to build new generation facilities. At present, SDG&E values this capacity through the Deliverability Value. This is calculated from the project-specific Market Price Referent with SDG&E's "all-in" TOD factors, less the project-specific Market Price Referent computed with SDG&E's "energy-only" TOD factors, with modifications to prevent negative capacity values in any given TOD period. This is done in order to maintain consistency with SDG&E's "all-in" TOD factors, which were designed to incorporate the effects of capacity value in TOD periods. The MPR itself is computed from the cost of a newly-built gas-fired power plant using publicly-available cost information. The Market Price Referent represents the levelized price, calculated using a cash flow modeling approach, at which the proxy CCGT revenues exactly equal the expected proxy CCGT costs on a net-present value (NPV) basis. The fixed and variable components of the MPR are calculated iteratively and then summed to produce an all-in MPR price. The MPR Model inputs include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs.

The main advantage of using the MPR Model over other production cost models or capacity valuation methods is that it is based upon cost and operating inputs that are publicly available, well documented, and familiar to both public and private participants. It relies upon forward costs of natural gas, CEC estimates of operating costs, and historically known plant construction costs updated with econometric indices. Furthermore, since it is based upon a conventional resource, and conventional resources are known to provide the maximum capacity benefits to a bulk power system, it is a reasonably good measurement of capacity value. As a generic model, however, it cannot address location-specific issues of individual generators. It also cannot be used to compare the renewable resources to other renewable resources, as it is based upon a conventional resource.

A summary of the pros and cons of using the MPR model is set forth below.

Pros	Cons
Well known in the California and transparent to IOU's and CA Market participants	The MPR does not address portfolio fit, but rather non-location specific value.
Ensure the same approach among 3 IOUs	The MPR reflects the cost of a natural gas-fired facility, which is not directly comparable to the cost of a renewable resource
Continuity and transparency of the LCBF process	The complexity behind MPR derivation is more complex than the valuation methodology

XIV. PRELIMINARY INDEPENDENT EVALUATOR REPORT

The ACR solicits comments regarding the strengths and weaknesses of a proposal to require the portion of the Preliminary Independent Evaluator Report evaluating bid solicitation materials and LCBF methodology to be submitted as part of the proposed RPS Procurement Plan. SDG&E notes that it already collaborates with its Independent Evaluator regarding its RPS Procurement Plan and that the proposal to formalize what is currently a routine process is not necessary and will compromise efficiency. While this proposal may have potential benefits, the drawbacks of possible usage of the information by potential bidders for gaming purposes as well as the premature nature of the report outweigh these benefits. The IE should be able to recommend process improvements candidly and confidentially throughout the process and up to bid evaluation. A summary of the pros and cons of this proposal is set forth below.

Pros	Cons
ffi The IE can formally ensure that the LCBF criteria explanation will foster maximum participation while discouraging gaming. ffi By addressing the LCBF twice, the	ffi The optimal time for recommendations is after the evaluation is complete so that the full effect of the LCBF can be considered. ffi Requiring the IE to explain in great detail how the LCBF criteria are used in bid

CPUC will be able to see how well the evaluation reflected the set of bids received.	evaluation could be conducive to bid gaming. ffi The proposed process will be circular and administratively cumbersome. It requires the submittal of a finalized plan and associated documents to the IE for comment, after which it must again be revised, all within what it typically a very tight timeline. ffi It is much more efficient and timely to work with the IE throughout the process – as is standard practice – rather than to work independently and combine comments at the end.

XV. USE CAISO TRANSMISSION COST STUDY ESTIMATES IN LCBF EVALUATIONS

Phase II study estimates and estimates performed in feasibility and system impact studies in areas outside CAISO are considered the most accurate and complete set of information regarding project-specific costs. However, they rely upon a time-consuming study process where project bidders within the CAISO must apply for interconnection and frequently wait for two to three years for a final study. The limited and focused scope of the Phase II study is considered confidential information for the project developer. Also, the inability to use non-public transmission information limits the usability of these studies for general public discussion and makes them impractical for routine hypothetical cost estimates of projected future "generic" resources.

The TRCR method provides for a publicly available method of estimating transmission interconnection costs, but is of questionable value. The TRCR method is intended to provide a broad cluster-level overview of interconnection costs and does not provide estimates of costs for project-specific upgrades that are not anticipated within the TRCR study.

Another drawback of the TRCR system is that it does not provide estimates of distribution-level network upgrades (which are typically provided in project-specific SGIP/WDAT studies or Rule 21 interconnection studies). It also does not cover most areas outside of the CAISO that do not deliver to a CAISO delivery point. For such non-CAISO projects, there are no estimates of interconnection costs other than those studies performed by the non-CAISO transmission operator.

SDG&E has used a both sources of data in past RFOs, with study-level data being used where available and TRCR data being used where it was not. While SDG&E believes that this approach has produced fair results in the past, this method could unfairly bias the evaluation process in favor of projects with CAISO study data. Evaluating all projects using TRCR data would solve this potential problem, but could create a disadvantage for developers who have Phase II study results that estimate lower upgrade costs than the TRCR study shows. In addition, projects with Phase II studies are likely to have a viability advantage over projects which have not filed for interconnection or have not filed early enough to receive interconnection study results. SDG&E believes that a hybrid approach is the most sensible overall approach to the problem of transmission upgrade cost estimation in a competitive evaluation. SDG&E suggests that its initial evaluation be based solely on TRCR data. Once it has established a shortlist, however, SDG&E should be able to evaluate any additional transmission cost data that the developer provides, including Phase II studies, to ensure that it has selected the appropriate projects.

Projects with existing interconnections should not have any upgrade costs assigned, unless the project is a repower or expansion of existing facilities or otherwise requires modifications to an existing interconnection to meet new standards.

A summary of the pros and cons of this proposal is set forth below.

TRCR only	
Pro	Con

ffi Public source of cost information - does not require confidentiality ffi Can be used for any project, whether inside or outside of queue process ffi Can be used for hypothetical transmission-connected projects	ffi Cluster level cost data only, cannot be used for precise project-level cost estimates ffi Does not include costs for PTO interconnection or distribution-level upgrades ffi Not a legally binding cost estimate - may lead to unreasonable expectations in negotiating process ffi Can impair fair evaluation of projects with cost studies ffi Does not cover non-CAISO projects

CAISO/PTO studies only	
Pro	Con
ffi Specific project-level determination of required upgrades and associated costs ffi Includes interconnection and distribution-level upgrade costs (through SGIP/WDAT) where applicable ffi Costs under interconnection agreements cannot exceed costs in studies under CAISO tariff (at present)	ffi Long lead time - may require 2-3 years of waiting before available ffi Study results are provided to developer and are considered confidential ffi Impractical for hypothetical projects ffi Can impair fair evaluation of projects without cost studies

Hybrid approach	
Pro	Con
ffi Provides most comprehensive set of information from which projects can be evaluated	ffi Results of CAISO studies do not always correlate with TRCR due to differing study scope ffi Does not provide information on projects at distribution-level which have not completed SGIP/WDAT or Rule 21 interconnection studies

XVI. CREATE TWO SHORTLISTS BASED ON STATUS OF TRANSMISSION STUDY

The ACR proposes that IOUs create Primary and Provisional shortlists. Projects on the Primary shortlist will have obtained CAISO GIP Phase II study results or equivalent, or executed Interconnection Agreements. The Provisional shortlist will contain projects that do not qualify as Primary. To encourage competition, it should be clarified that projects on the Primary shortlist should be permitted to lower their prices at any time. Additionally, timing must be considered in relation to pricing. If there are two projects with the same COD, but with different costs (higher on Primary list, and lower on Provisional list), IOUs should not be required to prematurely procure the more expensive Primary list project without knowing if the Provisional project is able to move to the Primary list. IOU's should also be able to begin working on PPAs with projects on the Primary shortlist regardless of the status of projects on the Provisional shortlist. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi The Provisional "Wait List" will encourage competition. ffi The two lists will inform procurement decisions by providing a pre-approved list of projects that are both viable and cost recoverable, and a pre-approved	ffi This proposal is unclear in regards to the relationship between pricing and timing between the two shortlists. ffi This proposal is unclear as to how the status of projects on the Provisional shortlist may affect

pipeline of projects that are able to move into this first category. ffi The two lists will offer insight into the procurement landscape by showing what types of projects are viable and available.	those on the Primary shortlist.

XVII. SHORTLISTS EXPIRE AFTER 12 MONTHS

The ACR proposes that shortlisted bids be executed within 12 months from the day that the IOU submits its final shortlist (consisting of both Primary and Provisional bids) to the Commission for approval. SDG&E is generally in favor of this approach. In order to discourage the incentive for either party to stall negotiations in order to let the clock expire, the Commission should emphasize that both parties are obligated to negotiate in good faith for the 12 month period. The 12 month limit should not apply to PPAs for projects in which the utility intends to invest. These PPAs are associated with larger transactions (equity contribution agreements) that typically take longer that one year to negotiate. If such a project is solicited through an RFO process, it should not be subject to this limitation. Since the prices for such PPAs are typically based on actual costs plus a negotiated rate of return, it is less likely that the longer negotiation period will result in a mismatch between the contract price and the market. Therefore, excluding these contracts from the 12 month limit should not increase the risk of such a mismatch. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi Decreases risk that the market will change drastically between the time the project is shortlisted and when the contract is signed. At the end of 12 months, if the market has shifted so that the contract price is no longer competitive, the project would have to bid into the next RFO and compete against current market prices.	ffi Does not totally eliminate the risk that the market will change drastically between the time the project is shortlisted and when the contract is signed. For example, contracts that SDG&E initially evaluated in mid 2010 had to be re-evaluated in early 2011 when it became clear that solar panel prices had drastically declined. Could create a perverse incentive to stall

ﬃ Provides clarity to the market. If the two-tiered shortlist approach is adopted, the 12 month cutoff provides more certainty to provisionally shortlisted bidders with whom SDG&E has not initiated negotiations. If SDG&E does not initiate negotiations within 12 months, the provisionally shortlisted bidders would be released from such shortlist and free to re-bid their projects.	negotiations. If the developer sees that market prices are trending upward, it might chose to stall in order to get out of the deal which is bound by the original bid price. Conversely, if the utility sees that market prices are trending down, it might feel obligated to discontinue negotiations in order to force the developer to bid the project into the next RFO at a lower price.

XVIII. TWO-YEAR PROCUREMENT AUTHORIZATION

SDG&E believes that a 2-year procurement authorization cycle would benefit the procurement process by allowing utilities to procure more efficiently. Instead of holding annual solicitations, even when the utility does not foresee a near term need, the utility could schedule its solicitations within the 2-year period in accordance with its projected need. As the utilities approach compliance with RPS goals, even based on probability weighted deliveries from existing projects, annual solicitations may no longer make sense. As discussion in Section VI above, utilities must procure additional resources above the compliance target based on probability weighted expectations of performance from existing contracts. When the utility has met this probability weighted need for a certain compliance period, the utility should not solicit additional projects that will deliver large volumes during such compliance period. Doing so would send inappropriate signals to the market and distract developers with the fruitless task of preparing a proposal for a project that has little to no chance of being selected. Instead, the Commission should authorize the utility to potentially hold RFO only every other year. In between RFOs, the utility would monitor the performance of its existing portfolio, progress of projects under development and other market conditions to determine whether it would need to use any of the following tools to make up for unanticipated procurement need: (a) procure Category 3 products to make up for small volumes; (b) utilize banked procurement when available; and/or (c) procure additional category 1 or 2 products to make up larger volumes. SDG&E does not believe that the current procurement process moves fast enough to warrant required annual solicitations. The two year procurement authorization cycle is more appropriate as the utilities approach full compliance. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi Provides flexibility to procure only when necessary. For example, as discussed in Section I above, SDG&E expects to be able to achieve RPS goals for CP2 with contracts that it has already executed, and is currently focused primarily on procurement of projects that will provide most of their generation in the third compliance period. Holding an RFO in 2012 to solicit projects that will begin deliveries in 2017 may not be ideal because SDG&E would likely be procuring projects that are at very early stages of development when it is difficult, if not impossible, to assess project viability.	ffi Project failures, spikes in retail sales, transmission failures or other unanticipated market pressures could result in the need to procure additional resources in a year when the utility will not hold an RFO. ffi Could increase instances when bilateral procurement must be benchmarked to outdated solicitation data. Potential Solution: ffi Bilateral projects must contain pricing that is indexed to the price of the applicable generator technology (solar panels, wind turbines, etc). The price would be adjusted at COD based on the market index. This could result in a lower price or a higher price depending on the market at COD. ffi Other potential solutions are discussed in section 6.9 above.

XIX. UTILIZE THE COMMISSION'S RPS PROCUREMENT PROCESS TO MINIMIZE TRANSMISSION COSTS

The Commission has proposed a process to better align the RPS procurement process with the CAISO's transmission planning process. The basic proposal can be summarized in 4 steps:

Step 1: CAISO determines how much capacity is available in each study area

Step 2: IOUS develop shortlists

Step 3: IOUs submit draft shortlist to the Commission

Step 4: If too many projects are shortlisted in a certain study area, CPUC rations out capacity to best ranked projects among all IOUs and confirms results with CAISO

Step 5: Losing bids remain on shortlist but cannot be executed unless another project does not get executed within 12 months.

SDG&E is generally in favor of this proposal and is supportive of this effort to more efficiently allocate available transmission capacity. A summary of the pros and cons of this approach is set forth below, along with specific suggestions to improve this process.

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///
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Summary of Proposal	Pros	Cons	SDG&E position
CAISO establishes available MWs in each study area based on RPS goals, and then subtracts this volume of capacity from signed PPAs. The balance is available for newly shortlisted projects.	ffi This methodology is based on the CAISO's recent efforts to improve its transmission planning process ("TPP") by planning for upgrades necessary to achieve 33% rather than upgrades necessary to build all projects in the interconnection queue. The benefit is that projects will no longer receive study results that require upgrades based on the existence of projects that may never come only.	ffi The CAISO's new process will shift the burden of paying for upgrade costs from developers to ratepayers. SDG&E proposes that other measures should be taken to ensure that this valuable capacity is allocated to the most viable and cost effective projects as developers will no longer bear the upfront risk of upgrade costs.	SDG&E agrees that viable projects should be analyzed as such – without the impact of conceptual projects sitting in the queue that will likely never come to fruition. However, SDG&E acknowledges that the resulting shift in risk from developers to ratepayers should be mitigated by a process that clearly prioritizes the most viable and cost effective projects.
IOUS develop shortlists and submit draft shortlist to the Commission	ffi No changes from previous process.		
If too many projects are shortlisted in a certain study area, CPUC rations out capacity to best ranked projects among all IOUs and confirms results with CAISO	ffi This process prevents IOUs from negotiating contracts with projects that cannot be supported by the upgrades that the CAISO has determined are necessary to achieve 33%.	ffi This process depends on an accurate allocation by the CAISO of the upgrades that will be necessary to achieve 33% ffi It may be difficult to determine which project should be awarded the available capacity. The CPUC should consider more than just price. For example, if SCE and SDG&E both have projects shortlisted in the	SDG&E supports a procedure to determine the most viable and valuable projects, but this proposal does present several issues of concern. The first is an accurate assessment by the CAISO and the application of this data by the CPUC. The CPUC should acknowledge that its rationing procedure may

		same study area and only one can be built, the Commission may chose SCE's project because it has a lower ranking price, but SDG&E may have fewer alternatives for securing its RPS compliance. SCE's project may be cheaper, but SDG&E may have a greater need for its more expensive project. If only one can be built, it should be the less expensive project, but the Commission must acknowledge that this process could create an additional barrier to achieving RPS goals. ffi As proposed, the timeline includes multiple points where approval is required – this could cause uncertainty and impede project development. The following is an estimated timeline following the proposal steps, if accurate, a developer would wait approximately 9 months after RFO issuance to know if their project has been shortlisted: a. CAISO determines deliverability that can be supported by the grid without additional high-cost DNU, and deducts PPA's executed in each study area to determine full capacity deliverability remaining for	impair an IOU's ability to reach its RPS goals. It is also important to consider how the proposed timeline will affect project development. SDG&E currently notifies developers of shortlist selection within approximately 5 months of RFO issuance. It is unclear how significantly this timeframe would be altered by this proposed process, and if significant how renewable development would be affected.

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		consideration in annual RPS procurement process: Cluster results generally available at the end of each year, add 1 month to determine deliverability available by study area, assuming CAISO has information readily available (Example: Cluster study complete 12/31/12, Results to CPUC 1/31/13) b. IOUs initiate solicitation, and submit draft shortlist to CPUC: approximately 6 months for RFO and bid analysis (Example: Issue RFO 10/1/12, Submit draft shortlist 3/31/13) c. CPUC rations any projects exceeding threshold in an area: assume 1 month for CPUC analysis and results (Example: Shortlist received 3/31/13, Analysis complete 4/30/13) d. CPUC sends results to CAISO: assume 1 month for verification (Example: Received 4/30/13, Validated 5/31/13) e. CPUC provides results to IOUs, IOUs finalize shortlists and submit to CPUC: assume 1 month to finalize and submit (Example: Results received 5/31/13, Shortlist issued 6/30/13)	

Losing bids remain on shortlist but cannot be executed unless another project does not get executed within 12 months	ffi See comments to 7.4 and 7.5 above.		
Comments on Overall Proposal	ffi Helps to eliminate exorbitantly high and inaccurate upgrade cost estimates that assume that more generation will come on line than what is needed to achieve RPS goals.	ffi Difficult to determine which projects are most deserving of the available capacity.	ffi This proposal will shift risk from developers to ratepayers. To make this an effective program addition, the proposal should be structured to safeguard ratepayer interests. To mitigate ratepayer risk, this process must ensure that developers have sufficient certainty to develop enough projects to create a robust and competitive market for RPS procurement. To this end, the shortlist process should facilitate project development by establishing a clear timeline (with dates) to provide developers with as much certainty as possible. The CPUC must also acknowledge the potential additional barrier the rationing process may create for IOU's in achieving their RPS goals.

Attachment 2

Amended Appendix C – Evaluation Methodology (LCBF Process)

SDG&E's RPS RFO Evaluation Methodology

Below is the assessment methodology and process to be taken by SDG&E and the Independent Evaluator ("IE") to ensure that the bid selection process is transparent and does not favor any technology or counterparty, and is aligned with SDG&E's compliance requirements. Although SDG&E worked diligently with its IE to develop this methodology, this document may require adjustment before issuing of the RFO in order to account for potential market, regulatory, and/or business context changes.

1. Prep-work prior to launching the RFO, gather data to provide a market benchmark. Analysis to be shared with the IE for input and endorsement.

   a. Compliance Period 1

   ffi SDG&E team to obtain the SP 15 forward curve for 7x24 2013 deliveries. This curve will be used in the evaluation of short-term bundled deals to derive the implied green attribute price being offered.
   ffi Continue to gather market quotes for unbundled RECs (quotes from brokers and etc.). This information will be used to assess whether the bids received are generally within the market range and to help identify potential areas of collusion or market manipulation.

   b. Compliance Period 3

      ffi SDG&E team to update the CPUC approved Market Price Referent (MPR) matrixes, mainly by updating these for natural gas prices, for their use in the evaluation of above market prices, as discussed below.

2. Prior to the closing date (TBD) at Noon, receive all bids:

   a. Upon being uploaded to SDG&E's RFO server, all bids are concurrently emailed to the IE and the SDG&E RFO team.

   b. 60-mins past noon on the closing date, the RFO email will accept bids that, because of heavy traffic by the deadline, could not be uploaded via the website (if the developer shows the print screen of the error message). The IE makes the call at 1:00 pm of "no more bids".

3. Between the closing date at Noon and the next business day after closing date, COB, organize bid data:

   a. All bids are assembled into a folder taxonomy designed by the IE.

   b. All bids are saved into the folder taxonomy prepared in Step 3.a. The IE and SDG&E will run a macro to compare folder structures and file sizes to ensure the bid population of the IE is identical to the bid population to be analyzed by the SDG&E RFO team. To the extent the folders do not match, a reconciliation effort begins until folders match.

c. Convert all bundled bids into TOD-adjusted pricing units, categorized by pricing type (e.g: Index, fixed price and etc.). For clarity, this conversion will not be applicable to the price of unbundled REC Bids.

d. The relevant data of all bids is exported into an Access database for analysis.

4. Initial Bid Assessment

a. For bundled products, convert post-TOD adjusted Bid prices into the Above Market prices as follows:

- The post TOD-adjusted (or flat) prices of Traditional Structure offers and fixed-price Portfolio Structure offers will be converted into Above Market Costs by subtracting the relevant Market Referent Price (MPR) from each Offer Price. This metric will be in the LCBF calculation and therefore is one of the key drivers of the selection process
- For Portfolio Structure bids with indexed null power prices, the fixed REC price component of each bid will be directly assigned as the Above Market Cost.

b. For unbundled RECs, the REC price will be directly assigned as the Above Market Cost to be compared against the Above Market Cost of all other bids.

c. A snapshot of the key statistics of the bids is produced for presentation to the PRG. These statistics will not include prices; at this stage of the process, bids have not been checked for conformance vis-à-vis the RFO requirements.

d. SDG&E and IE will jointly prepare the relevant data needed for the SDG&E Transmission Planning team to calculate Congestion Costs. This process will group together, on a no-name basis, the relevant data of bids (mainly anticipated generation and energy delivery profile) by interconnection points. The IE will then forward this information to SDG&E's Transmission Planning team.

e. Transmission Planning will run studies to determine hourly congestion costs associated with each of the proposed offer groups and provide results to SDG&E's evaluation team and IE.

f. Determine Transmission Cost Adder: For offers for new projects or projects proposing to increase the size of existing facilities, SDG&E performs an initial analysis of costs for transmission network upgrades or additions using the Transmission Cost Ranking Reports ("TRCR") approved by the CPUC. SDG&E anticipates that some bid respondents will fail to participate in a TRCR. Rather than considering these bids to be non-conforming, SDG&E evaluates the offers in order to determine whether the bid's all-in Price could provide a benefit to ratepayers. SDG&E will use TRCR's to estimate transmission costs for these projects. SDG&E will impute costs for these projects only if the total MWs in the applicable TRCR cluster could accommodate the offer that did not participate in the TRCR study.

g. Determine Deliverability Adder: Projects that have energy-only interconnections, or that cannot interconnect directly with elements of the transmission system located within SDG&E's service territory, may be subject to a deliverability adder based upon the difference between a project's TOD-adjusted MPR with and without capacity valuation to capture costs associated with future resource acquisition needs into SDG&E's overall energy and capacity portfolio.

For the next RPS RFO, SDG&E will use a deliverability calculation based upon the differences between SDG&E's approved "Capacity Adjusted" TOD Factors and the Energy Only TOD Factors used in the past. For each TOD period, SDG&E will calculate two TOD-adjusted MPR values; one calculated with the Capacity Adjusted TOD Factors, and one calculated with the Energy Only TOD Factors. SDG&E will then calculate the difference between the two (Capacity Adjusted value minus Energy Only value), replacing any negative difference by zero. The load-weighted average, in $/MWh, is the value of full deliverability for the given bid.

i. Capacity Adjusted TOD Factors and TOD Periods:

TOD Period	Period Days and Hours	Time-of-day Factor
Winter On-Peak	Nov 1 - Jun 30 Weekdays 1 pm to 9 pm PST (HE 14 to HE 21)	1.089
Winter Semi-Peak	Nov 1 - Jun 30 Weekdays 6 am to 1 pm PST (HE 7 to HE 13) Weekdays 9 pm to 10 pm PST (HE 22)	0.947
Winter Off-Peak	Nov 1 - Jun 30 All Weekend Hours NERC Holiday Hours and Weekday Hours not already considered On-Peak or Semi-Peak	0.679
Summer On-Peak	Jul 1 - Oct 31 Weekdays 11 am to 7 pm PST (HE 12 to HE 19)	2.501
Summer Semi-Peak	Jul 1 - Oct 31 Weekdays 6 am to 11 am PST (HE 7 to HE 11)	1.342

	Weekdays 7 pm to 10 pm PST (HE 20 to HE 22)	
Summer Off-Peak	Jul 1 - Oct 31 All Weekend Hours, NERC Holiday Hours and Weekday Hours not already considered On-Peak or Semi-Peak	0.801

ii. Energy Only TOD Factors and TOD Periods:

TOD Period	Period Days and Hours	Energy Only Time-of-day Factor
Winter On-Peak	Nov 1 - Jun 30 Weekdays 1 pm to 9 pm PST (HE 14 to HE 21)	1.192
Winter Semi-Peak	Nov 1 - Jun 30 Weekdays 6 am to 1 pm PST (HE 7 to HE 13) Weekdays 9 pm to 10 pm PST (HE 22)	1.078
Winter Off-Peak	Nov 1 - Jun 30 All Weekend Hours NERC Holiday Hours and Weekday Hours not already considered On-Peak or Semi-Peak	0.774
Summer On-Peak	Jul 1 - Oct 31 Weekdays 11 am to 7 pm PST (HE 12 to HE 19)	1.531
Summer Semi-Peak	Jul 1 - Oct 31 Weekdays 6 am to 11 am PST (HE 7 to HE 11) Weekdays 7 pm to 10 pm PST (HE 20 to HE 22)	1.181
Summer Off-Peak	Jul 1 - Oct 31 All Weekend Hours, NERC Holiday Hours and Weekday	0.900

	Hours not already considered On-Peak or Semi-Peak	

Projects with full deliverability interconnections are assumed to provide the full benefits of capacity, and thus will not receive a deliverability adder in the LCBF assessment of their bids. Projects that choose energy-only interconnections, or that are located outside of California ISO import points (unless dynamically scheduled), will be treated as having no deliverability benefits and the value of full deliverability will be added to their costs in the LCBF computation.

Due to constraints within the California transmission system, resources located within the California ISO but outside of the SDG&E area may not be able to provide full deliverability benefits to the SDG&E system even with a full deliverability interconnection. In such cases, the value of full deliverability for the project will be multiplied by the ratio of System Resource Adequacy payments to Local Resource Adequacy payments received or made by SDG&E prior to the beginning of the next RPS RFO. Currently, System Resource Adequacy is valued at approximately 60% of Local. The product, which is considered by SDG&E to be the current market view of the proportional value of system versus local deliverability within the California ISO, will be added to the cost in the LCBF computation.

Projects within the CAISO that seek full deliverability interconnections will not receive a deliverability adder if connecting within the SDG&E area, or a system deliverability adder if connecting to the CAISO outside of SDG&E's area but within California. Projects interconnecting with non-ISO California utilities that are located in California will receive a system deliverability adder. All energy-only interconnected projects will receive a deliverability adder. The table below indicates the type of adder that would be applied to various project types. Note that the PPA price that each project receives will reflect the project's ability to provide capacity value during the term of the contract.

INTERCONNECTION TYPE	IN SDG&E AREA	IN CALIFORNIA ISO; OUTSIDE SDG&E AREA	IMPORTS TO CAISO FROM WITHIN CALIFORNIA	IMPORTS TO CAISO FROM OUTSIDE CALIFORNIA
CAISO FULL CAPACITY DELIVERABILITY STATUS	No Deliverability Adder	40% of Deliverability Adder	40% of Deliverability Adder	Up to 40% of Deliverability Adder
ENERGY-ONLY	100% of Deliverability Adder	60% of Deliverability Adder	60% of Deliverability Adder	60% of Deliverability Adder

5. Develop DRAFT Short List:

The draft Short-list is a first-pass ranking that lets SDG&E determine which offers are most attractive based on a Preliminary LCBF price, which equals:

- **For bundled products**: the Above Market Costs + TRCR based transmission cost estimates + the Deliverability Adder (if applicable) measured in $/MW;
- **For unbundled RECs**: the unbundled REC price measured in $/MWh.

The "Preliminary LCBF" price does not include the congestion adder (all bids are assigned a zero congestion adder at this stage). At this point, bids have not yet been screened to determine whether they comply with RFO requirements. Note that for projects in SB2 categories 2 and 3, SDG&E's procurement will be limited by the statutory requirements and the Rim Rock settlement (if applicable).

a. Run query to group bids based on RPS compliance and SDG&E's identified need as follows:

Compliance Period 1: Deliveriesbetween Jan 1 2013 and December 31 2013

Compliance Period 3: CODbetween 4Q2016 and 1Q2017

Offers with deliveries outside these windows will be considered non-conforming, unless SDG&E's need assessment has changed materially between the time of issuance of this 2012 RPS Plan and the launching of the next RFO.

b. Determine RPS Compliance Period 1 Renewable Net Short ("RNS")

SDG&E's CP1 RNS is calculated as described in Section VI of its 2012 RPS Plan.

[redacted]

Given it will be 2013 by the time the RFO yields a shortlist, which is late into CP1, SDG&E anticipates that it will place a priority on 2011-2012 unbundled RECs (e.g. no development or production risk) and then on short-term bundled offers from existing facilities (e.g. no development risk) to fulfill CP1 need, if any.

c. Rank all the Compliance Period 1 Bids by preliminary LCBF price until 150% of SDG&E's CP1 RNS is fulfilled.

SDG&E will shortlist 150% of its CP1 RNS in order to provide an additional volume of potential projects that will be available if higher ranked projects do not materialize. SDG&E will divide its shortlist into 3 tiers, as discussed in Section 7 below.

d. Determine SDG&E's Compliance Period 2 RNS.

SDG&E does not expect to have a need to procure in CP2 and expects to bank any excess procurement into CP3.

e. Determine SDG&E's Compliance Period 3 RNS

SDG&E CP3 RNS is calculated as described in Section VI of its 2012 RPS Plan.

f. Rank all the CP3 Bids by preliminary LCBF price until one third of 150% of SDG&E's CP3 RNS is fulfilled.

SDG&E will shortlist one third of 150% of its CP3 RNS in order to provide a list of projects that will be available if higher ranked projects do not materialize[1]. SDG&E will divide its shortlist into 3 tiers, as discussed in Section 7 below.

g. Sunrise Powerlink ("SPL") After establishing these preliminary Shortlists, if SDG&E finds itself short of the SPL pledge, which is not the case today, SDG&E will consider SPL-eligible projects and add them to the shortlists to re-fill the pledge.

6. Final Short -Lists:

a. All offers in both preliminary Shortlists (CP 1 and CP 3) are screened for conformance[2]. To the extent offers are not conforming, SDG&E will likely discard

[1] The Compliance Period 3 need is divided by three because SDG&E expects to launch three yearly RFOs over the next few years to reach RPS compliance in 2020.
[2] Conformance check will start earlier if possible

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(given the high number of anticipated offers) or attempt to make it conforming via discussions with the counterparty provided that the non-conformance is minor.

b. Phase 2/GIA consideration (only for CP 3 offers). SDG&E will conduct sensitivity analyses around whether or not projects that have a CAISO Phase 2 interconnection studies or a signed Generator Interconnection Agreements change their shortlist status if this data, which is typically more precise, is available. If using the Phase 2 or LGIA data (as opposed to using the TRCR data) would move a project onto the shortlist, SDG&E will do so on the basis that having a Phase 2 or an LGIA is a strong sign of viability. If the opposite were true, SDG&E will apply judgment and endorse it with the IE and the PRG.

c. Adding Congestion Charges. SDG&E and the IE will add the relevant Congestion Charges to the Bids once obtained from SDG&E Transmission.

d. Qualitative Factors: SDG&E may differentiate offers of similar cost[3] by reviewing qualitative factors including: (in no particular order of preference)

- Project Viability[4]
- Local reliability
- Benefits to low income or minority communities
- Resource diversity
- Environmental stewardship
- Rate Impacts
- DBE factor

e. SDG&E and the IE will then develop the preliminary Final Short-Lists that includes congestion costs and Phase 2 study results if applicable. Qualitative factors, including project viability or Diverse Business Enterprise factors, will be used as a tie-breaker.

7. SDG&E's shortlists will be organized in 3 Tiers:

- **Tier 1 "Nominal Need":** the projects that are shortlisted because they fulfill SDG&E's Nominal Need, e.g. prior to applying probability weighting. SDG&E will require exclusivity as a condition for Tier 1 shortlisting.

[3] The term "similar cost" is used to indicate expected indifference by the PRG and CPUC as to the cost of one offer or another. The PRG will have access to SDG&E's evaluation and the quantitative and qualitative components of those offers prior to SDG&E's recommendation filing to the CPUC.

[4] SDG&E considers project viability as a qualitative factor and relies on the Energy Division's Project Viability Calculator and self-scores from the bidders. For projects that SDG&E rejects due to low viability scores, SDG&E rescores the projects to affirm the bidder did not unfairly score itself too low. For projects that SDG&E shortlists, SDG&E rescores the project to affirm that the bidder did not unfairly score itself too high. Projects below a certain viability threshold will not be considered for the shortlist.

- **Tier 2 "Risk Adjusted Need":** the projects that are shortlisted because they fulfill SDG&E's Risk Adjusted Need. For these, SDG&E will attempt to get exclusivity for a limited period.

- **Tier 3 "Contingency Need":** the projects that are shortlisted because they fulfill SDG&E's Contingency Need (150% of the Risk Adjusted Need). These projects will be shortlisted on a "stand-by" basis and counterparties will be informed of such. Exclusivity will not be required for Tier 3 shortlisting.

  a. The preliminary Final Shortlist is prepared and shared with the PRG during next viable meeting.

  b. SDG&E will consider PRG feedback before notifying bidders of whether they have been selected for the Final Shortlist.

RPS SHORTLIST CALCULATION
(CP1 through CP3)

The table below is illustrative of the methodology that SDG&E will use to determine its need by CP using the most updated data available at the time of the pre-bidders conference for the next RFO. Between now and then, there will be material changes to the position and therefore needs will be modified. The key message is that SDG&E: (i) will be seeking offers in CP1 if the portfolio underperforms between now and the next solicitation, and (ii) for CP3, it will procure any unmet need, net of CP2 into CP3 banking, over the course of 3 solicitations.

Compliance Period	RPS Target (GWh)	Nominal Need (Tier 1 Shortlist)	Risk Adjusted Need (Tier 2 Shortlist)	Contingent Need (Tier 3 Shortlist)
1	TBD	TBD	TBD	TBD
2	TBD	None	None	None
3	TBD	TBD	TBD	TBD

Attachment 3
Redline Plan Document

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SDG&E 2012 RPS PROCUREMENT PLAN

~~I.~~ I. ASSESSMENT OF RPS PORTFOLIO SUPPLIES AND DEMAND - § 399.13(A)(5)(A)

A. Overview

SDG&E's 2012 RPS Procurement Plan ("RPS Plan") describes how SDG&E will determine its procurement needs and how it will manage its RPS portfolio to ensure that it meets RPS compliance targets in a cost effective manner. The RPS Plan is designed to procure Least Cost Best Fit ("LCBF") renewable eligible resources so that SDG&E can serve its customers achieving the following levels of deliveries by Compliance Period ("CP"): (a) with an average of 20% of retail sales between January 1, 2011 and December 31, 2013, inclusive[1] ("CP1") (b) with 25% of retail sales by December 31, 2016, with reasonable progress made in 2014 and 2015[2] ("CP2"); (c) with 33% of retail sales by December 31, 2020, with reasonable progress made in 2017, 2018 and 2019[3] ("CP3"); and (d) with 33% of retail sales in each year beyond 2020[4] ("Post 2020 CP"). In order to determine how much energy to procure to meet these needs, SDG&E will follow the Need Determination Methodology described below. SDG&E will implement a work plan to fulfill its need, including soliciting additional multi-product and multi-term contracts through RPS solicitations, considering bilateral proposals, utilizing banked procurement, selling surplus generation when appropriate, and pursuing utility tax equity investment opportunities and/or utility ownership when economical and prudent.

B. Need Determination Methodology

SDG&E makes procurement decisions based on how its ~~probability weighted~~risk-adjusted RPS position- forecast (referred to herein as its "RPS position") compares to RPS compliance requirements, the result of which is its probability-weighted procurement need~~.~~ or Renewable Net Short ("RNS"). In order to calculate its RPS Position, SDG&E assigns a probability of success, following a qualitative and quantitative

[1] Compliance towards Compliance Period 1 goals shall be measured in accordance with D.11-12-020, Ordering Paragraph ("OP") 1.
[2] Compliance towards Compliance Period 2 goals shall be measured in accordance with D.11-12-020, OP 2.
[3] Compliance towards Compliance Period 3 goals shall be measured in accordance with D.11-12-020, OP 3.
[4] Compliance towards Post 2020 Compliance Period goals shall be measured in accordance with D.11-12-020, OP 4.

assessment, to the expected deliveries for each project in its portfolio[5] and then adds the ~~probability weighted~~risk-adjusted expected deliveries across all projects in its entire RPS portfolio. Probabilities are used because renewable projects and their deliveries are exposed to multiple risks and the flexible compliance mechanisms that allowed for borrowing from future procurement have been eliminated by recent legislation.[6] These risks include approval risks (for example, Commission approval and the timing of it), development risks (for example, permitting, financing, or transmission inter-connection), ~~-~~delivering risks (for example, generation fluctuations given the variant-intermittent nature of some renewable resources, or operational challenges), or other risks (for example, under-development transmission infrastructure common to a group of projects).

In general, if SDG&E's ~~probability weighted position forecast~~RPS Position is less than the RPS requirements, SDG&E will likely procure additional resources. If the ~~probability weighted position forecast~~RPS Position is greater than the RPS requirements, SDG&E will consider opportunities to bank or sell surplus generation. In addition, in order to optimize the relative value of renewable energy across compliance periods, SDG&E also considers short-term contracts when, for example, it is short[7] in the most immediate CP but long in the subsequent CP. SDG&E strives to have a well-diversified RPS portfolio so that its RPS compliance, particularly in the most immediate compliance period, is not unduly exposed to any given risk (for example, to a given technology, region, counterparty, etc.). SDG&E's RPS portfolio management ~~is about~~strategy involves identifying needs and risks and managing them as well as possible in a cost effective way.

The following sections explain SDG&E's methodology for determining its ~~procurement need.~~RNS. First, the process to compute the ~~probability weighted~~ RPS ~~position~~Position is explained. Then, needs by compliance periods are inferred by comparing RPS requirements to the ~~probability weighted RPS position forecast~~RPS Positions .

[5] For purposes of determining its RPS Position, SDG&E considers its portfolio to ~~includeall~~include all executed contracts until contract expiration (*e.g.* it does not assume expiring contracts will be renewed and excludes contracts under-negotiation unless indicated otherwise) and tax equity and UOG projects where relevant progress has been made (for example, Shu'luuk~~ or the Solar Energy Program).~~).

[6] Senate Bill (SB) 2 (1X)

[7] Throughout this document, the word "short" is used when the RPS ~~forecasted position~~Position is lower than the relevant RPS requirements and "long" when the RPS ~~forecasted position~~Position is higher than relevant RPS requirements.

1. The Assessment of Probability of Success for Various Project Types as a Key Component of Calculating ~~the Probability Weighted RPS Position Forecast~~RNS

SDG&E must assess the probability of success of the following main types of projects: (a) delivering; (b) approved but not yet delivering; and (c) not yet approved.[8] SDG&E evaluates the probability of success for each project in its portfolio on a monthly basis in order to calculate its ~~RPS probability weighted position forecast~~RNS, which is the basis for its procurement needs. To do this, SDG&E conducts a monthly review with an interdisciplinary team and uses the most up-to-date qualitative and quantitative information to assign a probability of success to each individual project. SDG&E's most up-to-date assessment is set forth in Section V below. SDG&E applies the following methodology to analyze each project type:

a. *Assessment of the Performance of Delivering Projects*

Projects that have already achieved commercial operation and begun delivering energy provide the most stable source of RPS energy when forecasting RPS procurement needs. These projects have overcome development hurdles and ~~are receiving~~receive a steady stream of income from their Power Purchase Agreement ("PPA"). However, it is crucial to consider the potential fluctuations in deliveries that these projects can experience and the impact that such fluctuations could have on SDG&E's need to procure additional resources to meet RPS goals. As discussed further in Section IV below, deliveries from these projects can be impacted by resource availability, regulatory changes, economic environment, operational performance, and evolving technologies. These types of fluctuations can be significant. For example, deliveries from a selection of SDG&E's wind portfolio differed by approximately 275 GWhs between 2010 and 2011, which equates to nearly 2% of SDG&E's 2010 retail sales. In order to ensure RPS compliance, SDG&E must account for these types of fluctuations, (and recognize the swings in production could be positive). The monitoring of performance of delivering contracts and the assessment of probabilities focuses on (a) understanding the historical profile of generation of each project and how it has differed year on year and relative to forecasts, and (b) the operational track record of any given generation. If the fluctuations in generation have been high and/or the operational track record has been poor, SDG&E assigns a lower than 100% probability, which

[8] See the ~~RPS Position table~~Renewable Net Short Calculation in Section ~~6.5~~V below.

typically ranges from 90-95% across the portfolio. Adjusting forecasts when necessary is a crucial component of SDG&~~E~~E's need assessment methodology.

b. Assessment of the Development Progress of CPUC Approved Projects That Have Not Yet Begun Delivering

Another important aspect of SDG&E's need assessment methodology is evaluating the development status of projects that the CPUC has approved, but have not begun delivering energy. These projects are typically much more risky than projects that have begun delivering because of the potential barriers that can arise during the development process to prevent a project from being built. Permitting, interconnection, financing and other development issues are discussed further in Section III below. SDG&E currently estimates that projects in development will have approximately a 60% success rate on average,[9] making the monitoring of development status the most critical aspect of SDG&E's need assessment methodology. SDG&E must account for development risks when determining its procurement needs. As with delivering contracts, SDG&E meets internally on a monthly basis to assign a probability of success to each of its developing projects. SDG&E's current is assessment is provided in the Renewable Net Short Calculation in Section V below.

c. Assessment of the Approval Queue for Projects that SDG&E Has Submitted to the CPUC, But Have Not Yet Been Approved

SDG&E meets at least monthly with Energy Division staff to discuss the likely approval timetable of projects that SDG&E has submitted to the CPUC for approval. The discussion focuses on when the Energy Division expects the Commission to act on such contracts and any potential timing constraints that might necessitate expedited Commission action or additional information needed. Since the Commission has indicated that it can take action on only one contract per business meeting,[10] SDG&E works collaboratively with the Commission to develop a work plan that results in timely approval. It is possible, however, that the shortage of Energy Division staff or other procedural challenges can result in approval delays that can impact a

[9] See section 6.5 for a list of SDG&E's risk assessment for each individual project.
[10] E-mail from Julie Fitch, former Energy Division Director, dated December 18, 2009.
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project's ability to come online. SDG&E must monitor this process closely to determine what, if any, impact it may have on the timing of expected deliveries.

2. Assess Other Portfolio Risk Factors

Once SDG&E has determined the probability of success for each of the contracts in its portfolio, SDG&E must also consider broader risk factors that can impact multiple projects or its entire portfolio, including: (a) fluctuations in retail sales; (b) the progress of key transmission upgrades/infrastructure; (c) contract termination (d) banking rules; (e) potential deficit from the prior RPS regime; and (f) the market for resale of surplus procurement. SDG&E evaluates the impact that each of these factors has on its portfolio on a monthly basis. SDG&E describes its methodology for analyzing these risk factors below.

a. Impact of Retail Sales Fluctuations

Since RPS compliance is based on a GWh target that is calculated using a percentage of retail sales, it is important to monitor fluctuations in forecasted retail sales. ~~At present,~~ Up until July of 2012, SDG&E used a retail sales forecast based on the ~~Commission's guidance,[11] SDG&E continues to use a forecast based upon the~~ California Energy Demand 2010-2020 Staff Revised Forecast Second Edition~~.[12] SDG&E expects that the CEC will approve an updated retail sales forecast in 2012 based upon filed workpapers~~[13]. At present, in accordance with the Commission's guidance,[14] SDG&E uses a forecast based upon the methodology determined in the 2010 LTPP bundled plans. The Commission explains that the 2010 LTPP decision[15] allows utilities to "use their own forecasts for bundled retail sales for the first five years and ~~results of the CEC's 2012~~

~~[11] D.07-12-052, p. 24.~~

~~[12] Kavalec, Chris and Tom Gorin, 2009. California Energy Demand 2010-2020, Staff Revised Forecast – Second Edition. California Energy Commission. CEC-200-2009-012-SF-REV. SDG&E adjusted the actual RPS forecast in April 2010 to align the RPS forecast with a rate case forecast, resulting in forecast loads approximately 1% lower than the bundled retail sales presented for SDG&E in the original CEC forecast. This adjustment had an immaterial impact to SDG&E's RPS need assessment.~~

[13] Kavalec, Chris and Tom Gorin, 2009. California Energy Demand 2010-2020, Staff Revised Forecast – Second Edition. California Energy Commission. CEC-200-2009-012-SF-REV. SDG&E adjusted the actual RPS forecast in April 2010 to align the RPS forecast with a rate case forecast, resulting in forecast loads approximately 1% lower than the bundled retail sales presented for SDG&E in the original CEC forecast. This adjustment had an immaterial impact to SDG&E's RPS need assessment.

[14] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012.

[15] D.12-01-033 (Decision Approving Modified Bundled Procurement Plans dated January 12, 2012).

~~IEPR Update Proceeding.~~~~[16]~~ ~~Based on recent trends, it is likely that the revised~~use the LTPP standardized planning assumptions thereafter[17]". Since SDG&E's current retail sales forecast ~~will show~~is lower ~~expected retail sales~~ than the ~~2010~~ forecast ~~provided.~~~~[18]~~ ~~If~~used in its initial 2012 RPS Plan filing[19], SDG&E's current RNS is also lower. SDG&E ~~were~~monitors its retail sales forecasts on a monthly basis in order to ~~base its RPS need forecast on a more current forecast of retail sales, its probability weighted RPS position would likely decrease by approximately 0.3% in Compliance Period 1~~identify potential fluctuations and ~~by approximately 2.3% in Compliance Period 2~~their impact to its RPS requirements.

~~[16] Latest documents can be found at http://www.energy.ca.gov/2012_energypolicy/documents/index.html. The Lead Commissioner Workshop on 2012-2022 Revised Staff Electricity and Natural Gas Demand Forecasts was held on February 23, 2012.~~

[17] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012.

~~[18] http://www.energy.ca.gov/2012_energypolicy/documents/2012-02-23_workshop/Mid_Case_LSE_and_Balancing_Authority_Forecast.xls~~

[19] San Diego Gas & Electric Company (U 902 E) 2012 Draft Renewable Procurement Plan, dated May 23, 2012.

b. Impact of Solar Panel Degradation

Contracts with solar PV developers incorporate a degradation factor which is used to forecast the project's performance over time as the panels age and become less efficient. As part of its RPS position calculation (both nominally[20] and probability weighted), SDG&E incorporates this contractual degradation factor in its probability weighted delivery. However, actual degradation can be higher or lower than the contractual degradation assumed. Over the next 2 years, as most of the larger Solar PPAs come online, SDG&E will add the monitoring of this variable as part of its RPS portfolio management practices.

c. Impact of Key Transmission Upgrades and/or Infrastructure

Transmission has long been recognized as a barrier to achieving RPS goals. SDG&E monitors the status of key transmission upgrades, such as the ~~Sunrise Powerlink transmission line, Eco Substation and~~Eco DREW ~~Substation~~Substations, on which multiple SDG&E RPS projects depend, in order to assess the potential impact of their delay or failure. Absent the deliveries that rely on these three key upgrades, SDG&E's need would increase materially, as shown in Table 2 in Section V below. The analysis presented bv SDG&E herein assumes that these transmission upgrades will be completed according to the current schedule. SDG&E continues, however, to monitor the progress of these transmission upgrades in order to assess potential delays and the corresponding potential need for incremental purchases.

d. Impact of Contract Renewal

SDG&E began signing RPS contracts in 2003, most of which had terms of 20 years. Some of these contracts are expected to deliver through 2023, and will impact SDG&E's procurement needs for the post 2020 Compliance Period. Some contracts for renewable energy procurement, however, were signed before the institution of the RPS program. Some of these contracts are scheduled to terminate during Compliance Period 2 and Compliance Period 3. As part of its RPS position calculation, and in accordance with Commission direction[21], SDG&E does not assume

[20] Nominal RPS position refers to a position estimated assuming that deliveries from contracts will occur as expected 100% of the time.

[21] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012

that these projects will be renewed. Owners of these projects will be asked to bid such projects into future RFOs to compete with other options that SDG&E has at that time. SDG&E believes that ratepayers will benefit from this additional supply being submitted into competitive solicitations.

e. Impact of Contract Termination

As part of its contract administration process, SDG&E actively monitors upcoming contractual conditions precedent that developers must meet (or waived) in order for the contract to continue to be viable. When SDG&E is the beneficiary of a condition precedent that may not be or has not been met, SDG&E will consider terminating the contract.

f. Impact of Banking Rules

RPS rules allow SDG&E to bank excess procurement from one compliance period for use in another, with exceptions for short term contracts and products that meet requirements for § 399.16(b)(3) products ("Category 3").[22] ~~The~~ In accordance with Commission ~~is currently working with stakeholders to implement this rule, but has not yet issued a final decision establishing with specificity what~~direction[23], SDG&E assumes for purposes of calculating its RNS that eligible excess procurement ~~may be counted as banked excess.~~[24] ~~SDG&E continues to monitor this process closely to assess how such rules~~[25] will ~~impact its ability to bank excess procurement for use~~be utilized in future compliance periods~~. In particular,~~[26]. SDG&E's ~~banking~~excess procurement position will be impacted by whether the Commission permits SDG&E to include generation from its Cabazon and Whitewater Green Attributes Purchase and Sales Agreements ("GAPSAs") in its excess procurement bank. SDG&E has explained that these agreements meet the requirements for contracts to "count in full" towards RPS

[22] Public Utilities Code § 399.13(a)(4)(B). All statutory references herein are to the Public Utilities Code unless otherwise noted.

[23] Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012 Procurement Plans dated August 2, 2012

[24] ~~*See* Section 3.7 of the *Proposed Decision Setting Compliance Rules for the Renewables Portfolio Standard Program*, issued April 24, 2012 in R11-05-005.~~

[25] Rules regarding excess procurement are set forth in D.12-06-038 (Decision Setting Compliance Rules for the Renewables Portfolio Standard Program dated June 27, 2012).

[26] Note that SDG&E may also manage excess procurement by selling such products when doing so would benefit ratepayers.

requirements, and that such grandfathered contracts should count towards its excess procurement bank.[27] The Commission has directed that grandfathered contracts do count towards excess procurement, but it has not yet provided direction on whether the GAPSAs qualify as grandfathered contracts. The Commission's direction on this issue will determine whether SDG&E is able to carry forward a potential excess procurement bank in CP1.[28] In CP 2, SDG&E expects that it will be able to bank potential excess procurement (into CP3) under all of the scenarios that have been contemplated by the Commission.

[27] *San Diego Gas & Electric Company Opening Comments on July 15, 2011 Ruling Requesting Comments on New Procurement Targets and Certain Compliance Requirements for the Renewable Portfolio Standard Program*, filed August 30, 2011 in R.11-05-005.
[28] See the RPS Banking Analysis table in Section V below

g. Impact of the ~~Potential~~ Deficit From 2010 RPS Program

Based on the Commission's recent ~~proposed~~ decision on RPS compliance rules,[29] SDG&E must ~~consider the possibility that it will be required to~~ carry forward a deficit from the former RPS regime, which required that retail sellers achieve 20% by 2010. Although SDG&E met these goals based on prior flexible compliance rules,[30] the ~~proposed~~ decision indicates that ~~new rules may require~~ SDG&E ~~to~~must carry forward a deficit into CP1. SDG&E has incorporated this ~~potential~~ deficit in its need assessment for CP1 based on the methodology provided by the ~~proposed~~ decision. SDG&E's calculation of this ~~potential~~ deficit is provided at Table ~~5~~3 in Section V below.

h. Impact of the Resale Market

SDG&E will closely monitor opportunities to sell excess procurement. SDG&E will assess the market when the opportunities arise to determine whether banking such excess procurement for use in a future compliance period or trying to sell it in the market is more advantageous for SDG&E ratepayers. If SDG&E believes that the current market price is high and expects that it will be able to fulfill any future needs with more economic options, it may choose to sell excess procurement instead of banking it.

i. Impact of Rim Rock Settlement

In July of 2011, the Commission approved a settlement agreement between SDG&E, NaturEner Rim Rock Wind Energy, LLC, the Division of Ratepayer Advocates ("DRA") and The Utility Reform Network ("TURN") (together, the "Settling Parties") to make a tax equity investment in the Rim Rock wind project located in Montana.[31] As part of the settlement agreement, SDG&E – subject to Rim Rock becoming operational and SDG&E making a tax equity investment in the project – agreed not to procure any incremental RECs from projects that are neither directly connected nor dynamically scheduled to a California-based Balancing Area Authority ("CBA") if such purchase would cause SDG&E to meet more than 25% of its RPS requirements with such RECs through December 31, 2017. Since SDG&E has already procured this type of out-of-state

[29] ~~Proposed~~ *Decision Setting Compliance Rules for the Renewable Portfolio Standard Program*, *supra*, note ~~17~~20.
[30] SDG&E's August 2011 RPS Compliance Filing dated August 1, 2011.
[31] *See* D.11-07-002.

generation up to the 25% limit established by the settlement, SDG&E is currently precluded from purchasing RECs from out-of-state projects that are not dynamically scheduled to a CBA, through the end of 2017. If Rim Rock does not become commercially operational or SDG&E does not make its tax equity investment in Rim Rock, this restriction will be removed and SDG&E will consider additional REC purchases in the period between 2012 and 2017.

3. Determine ~~the Compliance Needs~~RNS for Each Compliance Period

After probabilities are ~~assessed~~assigned to each project, SDG&E's ~~probability weighted RPS position forecast~~RNS is calculated by multiplying the forward contractual ~~deliveries~~delivery profiles (including degradation) ~~profile~~ of each project by each project's probability and then adding those generation profiles across the portfolio.[32] The discussion below describes SDG&E's current ~~procurement needs~~forecasted RNS for each compliance period based on its assessment as of ~~May 14~~August, 2012. More detail on SDG&E's needs in each compliance period is provided in Section V below.

a. Compliance Period 1 Procurement Needs

SDG&E intends to meet CP1 goals by maintaining a 20% procurement level in 2011, 2012, and 2013 on average. Based on deliveries from SDG&E's current portfolio of executed contracts, before applying any ~~probabilities of success~~risk adjustment, SDG&E would be able to meet CP1 requirements without additional procurement. Based on the ~~probability weighted~~risk adjusted portfolio in CP1, in order to meet the 20% requirement, SDG&E ~~must complete one contract under negotiation[33] and perhaps~~may have to conduct a relatively small unbundled REC purchase (in accordance with the Rim Rock settlement discussed in (I)(B)(2)(i) above) to offset the deficit carried into CP1 ~~approval if the pending compliance PD is approved as proposed.~~. Going forward, if relative to the current ~~probability weighted~~risk adjusted position, delivering projects underperform, developing projects fail or are delayed or if CPUC approvals are delayed (or not obtained), SDG&E will make additional purchases focusing on short term contracts (emphasis

[32] As explained above, SDG&E's practice is to exclude contracts under-negotiation and to not assume renewal for an expiring contract.

~~[33] GAPSAs for the Green Attributes of the Whitewater and Cabazon Wind facilities in 2012 and 2013.~~

on in-state unbundled RECs[34]). The rationale for focusing on either unbundled RECs or short-term bundled contracts is minimizing ratepayer cost in light of SDG&E's position in CP2. Lastly, if the generation from the relatively large volume of SDG&E projects anticipated to begin delivering in 2013 materially surpasses the current probability assessed profile and the Commission does not grant ~~grandfather~~grandfathered status to the Shell GAPSAs, SDG&E may become a seller in mid-to-late 2013.

b. Compliance Period 2 Procurement Needs

Based on current projections, SDG&E expects that it will meet Compliance Period 2 RPS goals with generation from contracts that have been executed together with the deliveries of tax equity and UOG initiatives where relevant progress has been made.[35] SDG&E intends to manage potential over-procurement by banking it for future compliance needs, terminating contracts where conditions precedent are not met, and/or selling such excess procurement.

c. Compliance Period 3 Procurement Needs

Based on SDG&E's current probability weighted RPS position forecast, the company ~~expects to~~may need to conduct new renewable eligible purchases (from either new ~~Greenfield~~greenfield projects, renewal upon expiration of existing contracts, or other available existing facilities) to meet its CP3 RPS requirement, 33% by 2020. The level of new purchases will be subject to the level of banking, if any, related to potential excess procurement in CP2 into CP3. SDG&E intends to fill this remaining need with viable low-cost opportunities from solicitations in 2012, 2013 and 2014, and with potential tax equity investments.

4. Utility Tax Equity Investment and Utility Ownership Opportunities

SDG&E participation as a tax equity investor in renewable projects enhances project viability (through securing of financing) and decreases costs for ratepayers (given SDG&E's cost of capital relative to renewable financing market). Tax equity investments by utilities and other non-traditional investors are particularly important in the future in light of the phase out of the

[34] The strategy will be different if multiple large projects fail and SDG&E must replace large portions of its portfolio.
[35] Includes Shu'luuk Wind and the Solar Energy Program.

Cash Grant.[36] Without the Cash Grant, developers without a sizable balance sheet rely on tax equity investors to monetize renewable incentives such as the Investment Tax Credit.

SDG&E's experience with tax equity investment has been favorable. The Rim Rock project (discussed above) was approved by the CPUC and the ~~Feneral~~Federal Energy Regulatory Commission ("FERC") and has an expected online date in Q4 2012.[37] SDG&E's Shu'luuk project is currently under negotiation for an expected online date in 2014. SDG&E intends to submit this project for Commission approval in 2012. Anticipated deliveries from these projects have been incorporated into SDG&E's forecasted RPS procurement need based on the probability of success that SDG&E assigned to them according to the process described above. SDG&E is also considering additional tax equity investment opportunities in two to three projects where: (a) its involvement might enhance viability of a project with an existing contract; and/or (b) where a promising cost competitive project with an online date just prior to the start of CP3 may have a positive socioeconomic impact, potentially involving a Diverse Business Enterprise.

SDG&E also continues to make progress on its Solar Energy Project,[38] pursuant to which SDG&E will build 26 MWs of utility-owned solar photovoltaic projects. SDG&E held a request for proposals in the fall of 2011 and is currently negotiating contracts with shortlisted contractors. SDG&E expects construction on these projects to begin in 2014. Anticipated deliveries from these projects have been incorporated into SDG&E's RPS procurement need forecast. Additional UOG opportunities are not anticipated at this time, but may be considered if economic and prudent.

II. POTENTIAL COMPLIANCE DELAYS- § 399.13(A)(5)(B)

The market for renewable energy is dynamic; multiple factors can impact project development and SDG&E's attainment of its RPS goals. The following discussion covers the major issues affecting both renewable project developers and SDG&E. It begins with the transmission, permitting, and financing hurdles faced during project development, and continues through the

[36] The American Recovery and Reinvestment Act of 2009 (H.R. 1), enacted in February 2009, created a renewable energy grant program that is administered by the U.S. Department of Treasury. This cash grant may be taken in lieu of the federal business energy investment tax credit ("ITC").
[37] D.11-07-002.
[38] Approved by D.08-07-017.

challenges experienced as a project matures – viability, debt equivalence, accounting issues, and regulatory uncertainty.

A. Transmission & Permitting

1. Interconnection Facility Delays

The timely approval, permitting, and completion of interconnection facilities are crucial to the successful development of SDG&E's renewable portfolio. Currently, the key transmission facilities that impact SDG&E's portfolio are: the ~~Sunrise Powerlink, the~~ ECO sub-station~~,~~ and the DREW switchyard. Unsuccessful development of these facilities will materially impact SDG&E's renewable portfolio.

~~When the Sunrise Powerlink goes into service, existing~~Existing transmission constraints between the Imperial Valley and the San Diego load center ~~will be~~have been largely resolved~~.~~ with the construction of the Sunrise Powerlink. However, the addition of the Sunrise Powerlink ~~(with expected in-service date June 2012)~~ and the signing of multiple PPAs in the Imperial Valley region do not, by themselves, guarantee the successful construction and interconnection of renewable generation facilities. SDG&E and developers are now focused on building the interconnection and network facilities necessary to interconnect and deliver this renewable energy to the transmission system, and they are facing significant permitting challenges. An example of these interconnection facilities is the proposed 230 kV "DREW" switchyard in Imperial Valley that will act as a collector switchyard for multiple renewable projects to connect to the transmission system with one line, reducing environmental impacts. However, as with any new construction of transmission infrastructure, there are environmental, permitting issues, and other challenges (mainly uncooperative land owners, and/or opposition from nearby residents) that can impede timely progress. Permitting has proven particularly difficult where land owners or permitting authorities have their own commercial interests that may compete with those of the renewable developers. Additionally, as is the case with the proposed ECO substation, which is designed to improve grid reliability for Eastern San Diego and also serve as a hub to connect and deliver renewable projects to San Diego, regulatory approvals are still pending causing uncertainty developers whose projects rely on this upgrade.

2. Interconnection Study Process

The California Independent System Operator's ("CAISO") process for determining required upgrades for renewable projects can cause significant delay and expense. SDG&E protects ratepayers by establishing transmission upgrade cost limits and including conditions precedents in the PPA whereby if the upgrade costs are higher than the thresholds established in the PPA, the contract can be terminated. In the past, developers have had to wait years for study results and in some cases have been faced with extremely high upgrade costs that make their projects unviable. Recent changes in the CAISO's approach for identifying network upgrades that provide interconnecting renewable generators with fully deliverable status appear to be reducing transmission funding hurdles for new generators. However, the process is still under development and SDG&E expects that this area will continue to be potential challenge.

3. Bureau of Land Management ("BLM") Delays

Uncertainty surrounding the availability and timely issuance of Right-of-Way Grants from the BLM creates development risks for project development. The BLM process established to secure land rights has proven to be time-consuming - creating uncertainty, scheduling challenges and corresponding problems with project elements such as financing, permitting, engineering, procurement and construction ("EPC") contracts and supplier contracts.

B. Project Finance, Tax Equity Financing, and Government Incentives

Financing is key for the successful development of renewable projects. Two areas of financing are of primary importance: (i) project financing relied upon to construct the project; and (ii) tax equity financing relied upon to monetize tax benefits such as the Production or Investment Tax Credits. Project Financing has traditionally been provided by financial institutions and costs and availability is a function of the overall health of the financial system. Tax equity financing has also traditionally been provided by banks or large corporations. In order to successfully finance, renewable projects generally need to: (i) complete permitting, (ii) have a long-term fixed price PPA from a credit-worthy offtaker, and (iii) have a bankable (or proven) technology. With the phase out of the Cash Grant and current turmoil in financial markets, non-traditional investors are key to the success of the renewable energy industry. Non-traditional investors include a wider institutional investor reached by projects issuing a security, or utilities and other corporations with tax appetite as tax equity investors.

The extension of the Federal Production Tax Credits ("PTCs") expiring in 2012 and the Investment Tax Credits ("ITCs") expiring in 2016 will be critical to the sustained success of renewable energy in the United States. The PTCs and ITCs currently represent about 33% of the economic value of renewable projects and without them, the relative competitiveness of renewable energy relative to fossil fuels, will be severely impacted.

C. Solar Panel Risk and Project Viability

SDG&E may be subject to industry and technology risks when selecting solar power projects to meet its RPS goals. For example, the industry is undergoing significant consolidation and attrition of market participants. Numerous manufacturers are experiencing severe financial difficulties or have gone bankrupt in response to intense competition and the significant declines in market prices. The risk to SDG&E is that the viability of some low-cost projects may depend on specific manufacturers that might go out of business, forcing the developer to seek other sources. Or, more significantly, the price of panels may increase before the purchase is final and greatly reduce the viability of the project. More industry shakeout is anticipated but prices are expected to stabilize, or increase, once the excess supply is absorbed by the market.

SDG&E also faces technology risks. The company tries to manage technology risks through diversification. For example, photovoltaic panel materials and manufacturing processes vary significantly. There are proven technologies with long operational and performance histories, but there are also newer technologies that have not yet been proven over the typical 20 year contract term. Final technology choices are made by project developers. The risk to the company is that a solar facility may fail to perform as intended due to panel failure or degradation, causing it to fall short of the minimum power delivery requirements. In this case the developer is subject to penalties but, if the failure is too great, the developer may abandon the project. Filing claims under solar panel warranties might be complicated further if the manufacturer is located overseas or is out of business. Such a catastrophic project failure with limited ability to cure through warranty claims could leave a significant short term deficit in the annual RPS goals.

D. Debt Equivalence & Accounting

Two other issues may challenge SDG&E's ability to achieve its RPS goals. The first involves debt equivalence. As SDG&E executes an increasing number of PPAs, the cumulative debt equivalence of all these agreements may greatly affect SDG&E's credit profile and, consequently, its financial standing. Rating agencies include long-term fixed financial obligations, such as power purchase agreements, in their credit risk analysis. These obligations are treated as additional debt during their financial ratio assessment. S&P views the following three ratios, Funds From Operations ("FFO") to Debt, FFO to Interest Expense, and Debt to Capitalization, as the critical components of a utility's credit profile. Debt equivalence negatively impacts all three ratios. Unless mitigated, a PPA would negatively impact SDG&E's credit profile by degrading credit ratios.

The second issue relates to Accounting Standards Codification (ASC) 810 Consolidation, which includes the subject of Consolidation of Variable Interest Entities previously referred to as "FIN 46(R)". Application of ASC 810 as it pertains to Consolidation of Variable Interest Entities (VIEs) could also impact SDG&E's ability to sign new contracts. As part of SDG&E's overall internal review and approval process for new PPAs, SDG&E conducts a review of whether each such PPA will be subject to consolidation under ASC 810. Under ASC 810, no renewable PPA has been deemed subject to such consolidation, however, ASC 810 requires SDG&E to perform an evergreen assessment for those contracts which are considered VIEs. For this reason, SDG&E believes that it is required to assess quarterly each contract or category of contracts to ensure continued compliance with ASC 810, to determine whether or not SDG&E must consolidate a Seller's financial information with SDG&E's own quarterly financial reports to the Securities and Exchange Commission. In particular, wind, solar, geothermal and bio-gas renewable Sellers could be impacted.

Application of ASC 810 could challenge SDG&E's ability to achieve its RPS goals, and add further costs, and risk to execution of new renewable contracts. If SDG&E determines that consolidation is required, a Seller must open its books to SDG&E and submit financial information, on a quarterly and monthly basis, as specified in SDG&E's contract language for the duration of any agreement.

All PPAs are affected by either debt equivalence or ASC 810 requirements. The Commission is well aware of the negative impact of debt equivalence on SDG&E's credit profile. AB 57 requires that the Commission adopt procurement plans that, among other objectives, enhance the creditworthiness of the utility. ASC 810 will affect SDG&E's reported financial data and may have a negative impact on SDG&E's balance sheet and/or credit profile. ASC 810 could impact SDG&E's capital structure on a consolidated basis and cause it to be misaligned with its authorized capital structure.

In order to rebalance to SDG&E's authorized capital structure, SDG&E would be required to infuse additional equity to offset the additional debt. Given that SDG&E will be executing contracts for 20% or more of its overall portfolio to meet its RPS goals, SDG&E anticipates that the Commission will address and mitigate the resulting overall impacts of debt equivalence and ASC 810 to SDG&E's capital structure in the context of SDG&E's recently-filed cost of capital application for test year 2013 filed on June 20, 2012.

E. RPS Cost Containment

The Commission is in the midst of implementing the changes to the RPS Program established by Senate Bill 2 (1X). As a result, full program details are not yet final which creates regulatory uncertainty. Two important outstanding items affecting procurement are RPS cost containment and Compliance proceedings.

An Energy Division staff proposal regarding RPS cost containment is anticipated later this year, with a proposed decision possibly being released in Q1 2013. The decision is expected to implement a cap on the amount of money that retail sellers can spend in an effort to meet RPS goals. Certainty surrounding this potential procurement limit will not be achieved until the final year of Compliance Period 1. This makes it difficult for IOU's to be proactive. It is unclear at this time what the limitation will be for SDG&E, how it will relate to the procurement dollars spent and contracts signed as of the date of the final decision, and how it will interact with the other requirements of the RPS program.

III. PROJECT DEVELOPMENT STATUS UPDATE - § 399.13(A)(5)(D)

As described further in Section I above, SDG&E regularly evaluates project development status to assess each project's ability to begin deliveries in a timely manner. SDG&E's portfolio of renewable energy resources currently under contract but not yet delivering generation are in various stages of development. It is anticipated that projects will enter commercial operation consistently from 2012 to 2015. Projects under development generally require numerous permitting approvals, generator interconnection, financing, and completion of construction before they can achieve commercial operation. Each of the above issues adds significant risk to the development of a project and can directly impact the success or failure of a project. SDG&E's experience is that achieving all of these milestones represents a significant challenge for developers. Although a developer's experience may improve a project's ability to achieve commercial operation, it does not insure that a project will be successful.

SDG&E saw increasing challenges among developers to secure financing after the United States entered the 2008 recession. Subsequently, as more projects were proposed in desert regions, permitting approvals took longer than developers expected due to increased scrutiny of environmental issues and permitting agency coordination efforts. Today, as many projects are obtaining agency permit approvals, there seems to be an increase in litigation challenging the CEQA/NEPA process potentially causing delays while claims are resolved. Throughout this period, the time to study and construct generator interconnection upgrades has grown much longer and significantly more expensive to the developer.

Each project bears significant development risk to resolve all issues necessary to meet commercial operation. SDG&E currently believes that a majority of projects can meet their commercial operation dates either on schedule or within the prescribed cure period. However, SDG&E does have projects that are experiencing possible development issues that could affect their ability to meet commercial operation. SDG&E's need assessment methodology, described in Section I above, takes all of these risks into consideration.

IV. RISK ASSESSMENT - § 399.13(A)(5)(F)

SDG&E also evaluates the risk that delivering projects will underperform. In SDG&E's experience, renewable projects have relatively low risk of non-performance. By achieving commercial operation, developers have made significant investments into the projects and are receiving timely payments for energy delivered. Developers are subject to penalties if they do not meet contractual requirements to supply at least the minimum energy contemplated. However, over the past decade, SDG&E has observed some dynamic factors that may affect power production from delivering projects:

- Resource Availability: For example, a bad wind year can greatly impact a wind facility's performance. Although the contract requires damages for underperformance in an effort to protect ratepayers, a bad wind year can still have an impact on SDG&E's ability to meet its RPS goals, as described in Section I above.

- Regulatory Changes: For example, the expiration of subsidies, such as the Public Goods Charge or the Production Tax Credit, lowers the revenue stream for RPS developers, and can lead to non-production or lower production.

- Economic environment: Specifically, the interest rates and flexibility of financing arrangement entered into by developers can impact the project's success. Long term project financing arrangements with unfavorable terms can lead to project failure or lower production.

- Operational Performance: For example, a facility can experience unexpected mechanical failures that impact performance.

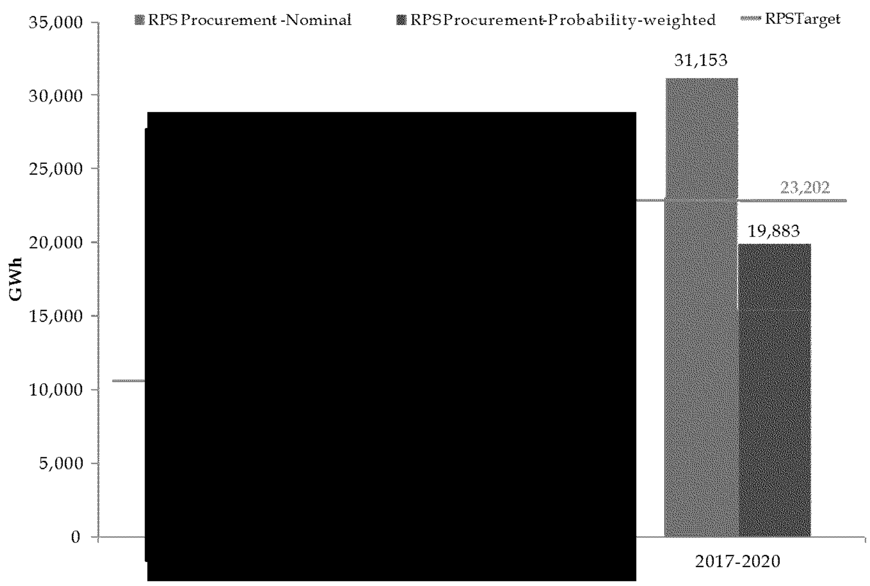
- Evolving technology: Facilities with older generation-technology that is no longer supported by the manufacturer can cause project failure or lower production. This problem is arising now for older RPS projects, and could repeat itself in 20 years when the projects being signed today begin to age.

SDG&E's assessment that current projects are at a low risk of non-performance is based on the above risk factors remaining relatively stable.

V. QUANTITATIVE INFORMATION- §§ 399.13(A)(5)(A), (B), (D), (F)

The following tables provide background data for SDG&E's need assessment as of May 2012.

~~**Table 1 – RPS Position**: This table shows SDG&E's current forecast of its nominal and probability weighted need. SDG&E's nominal need is based on expected deliveries from all signed contracts with no adjustments made to deliveries. The probability weighted need is calculated using the methodology described in Section I above. The pie charts show a breakdown of the project types that currently make up SDG&E's RPS portfolio in each compliance period.~~



~~Table 2~~Table 1**-RPS Sensitivity Analysis**: this table provides a summary of the impact of some of the key factors that can impact RPS performance.

[redacted]

[redacted]

* 0.0% stands for 23.8% of retail sales in CP1
** 0.0% stands for 41.9% of retail sales in CP2

Table ~~3~~2 – RPS Banking Analysis: this table provides a detailed analysis of the impact that the determination of whether the Cabazon and Whitewater GAPSAs are considered compliant with the "count in full" requirements of 399.16(d) (*i.e.* are "grandfathered~~"), and whether such grandfathered deliveries can count towards SDG&E's banked excess procurement.~~")."

Scenario 1: Cabazon/Whitewater GAPSAs are considered grandfathered

	CP1	CP2 - Nominal	[redacted]	CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,226,188	23,010,527	[redacted]	31,152,915	19,882,682
RECs* (MWh)	[redacted]	[redacted]	[redacted]	0	0
Short-term Contracts** (MWh)	[redacted]	[redacted]	[redacted]	0	0
Total RPS Bankable Deliveries(MWh)	[redacted]	[redacted]	[redacted]	31,152,915	19,882,682
RPS Target (MWh)	[redacted]	[redacted]	[redacted]	23,202,248	23,202,248
Above or Below Target	[redacted]	[redacted]	[redacted]	Above	Below
Bankable Energy(MWh)	[redacted]	[redacted]	[redacted]	7,950,667	(3,319,565)
Banking brought forward from Previous CP (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bankable Energy + Previous CP Bank (MWh)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Scenario 2: Cabazon/Whitewater GAPSAs are considered Category 1

	CP1	CP2 - Nominal	[redacted]	CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,226,188	23,010,527	[redacted]	31,152,915	19,882,682
RECs* (MWh)	[redacted]	[redacted]	[redacted]	0	0
Short-term Contracts** (MWh)	[redacted]	[redacted]	[redacted]	0	0
Total RPS Bankable Deliveries(MWh)	[redacted]	[redacted]	[redacted]	31,152,915	19,882,682
RPS Target (MWh)	[redacted]	[redacted]	[redacted]	23,202,248	23,202,248
Above or Below Target	[redacted]	[redacted]	[redacted]	Above	Below
Bankable Energy(MWh)	[redacted]	[redacted]	[redacted]	7,950,667	(3,319,565)
Banking brought forward from Previous CP (MWh)		[redacted]	[redacted]	[redacted]	[redacted]
Bankable Energy + Previous CP Bank (MWh)		[redacted]	[redacted]	[redacted]	[redacted]

* *Includes 2010 RECs from Sierra Pacific (in-State).*
** *Includes Silicon Valley Power, Calpine, Edison 1 & 2 and Mesa.*
*** *Assumes all grandfathered contracts are not subject to SB2 banking restrictions*

SB_GT&S_0561871

Scenario 1 - Cabazon/Whitewater GAPSAs are Grandfathered

	CP1	CP2 - Nominal	[redacted]	CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,318,519	23,184,345	[redacted]	31,451,135	22,638,025
Unbundled RECs* (MWh)	[redacted]			0	0
Short-term Contracts** (MWh)				0	0
Total RPS Bankable Deliveries (MWh)				31,451,135	22,638,025
RPS Target (MWh)				22,212,560	22,212,560
Above or Below Target				Above	Above
Bankable Energy (MWh)				9,238,575	425,465

Banking brought forward from Previous CP (MWh)	[redacted]			[redacted]	[redacted]
Bankable Energy + Previous CP Bank (MWh)				[redacted]	[redacted]

[redacted]

Scenario 2- Cabazon/Whitewater GAPSAs are ~~Category 1~~

	CP1	CP2 - Nominal	[redacted]	CP3 - Nominal	CP3-PW
Total RPS Deliveries(MWh)	12,318,519	23,184,345	[redacted]	31,451,135	22,638,025
Unbundled RECs* (MWh)	[redacted]			0	0
Short-term Contracts** (MWh)				0	0
Total RPS Bankable Deliveries (MWh)				31,451,135	22,638,025
RPS Target (MWh)				22,212,560	22,212,560
Above or Below Target				Above	Above
Bankable Energy (MWh)				9,238,575	425,465

Banking brought forward from Previous CP (MWh)	[redacted]			[redacted]	[redacted]
Bankable Energy + Previous CP Bank (MWh)				[redacted]	[redacted]

[redacted]

Table ~~**4 – Impact of Retail Sales**: The table below shows the difference between the CEC approved retail sales forecast and SDG&E's alternate retail sales forecast.~~

	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
OriginalRS(MWh)	16,249,031	[redacted]				8,595,626	18,873,220	19,154,172	19,454,994	19,759,758
OrignialRS embedded growthrate						1.4%	1.5%	1.5%	1.6%	1.6%
AdjustedRS withembedded rate	16,249,031					17,595,979	17,858,650	18,124,499	18,409,150	18,697,530
Generation(MWh)-- Nominal	3,380,171					8,193,487	8,195,990	7,812,768	7,673,622	7,470,535
Generation(MWh)-- Prob Weighted	3,380,171					5,349,684	5,330,863	4,990,805	4,869,324	4,691,690
Deliveries(MWh) – Nominal								31,152,915		
Deliveries – Prob Weighted								19,882,682		
~~RPS Target~~								~~23,202,248~~		

~~Table 53~~ - Impact of Potential Deficit From Prior Compliance Regime:

SB_GT&S_0561872

RPS Procurement and Targets (MWh)	2003	2004	2005	2006	2007	2008	2009	2010
Bundled Retail Sales	15,043,865	15,811,591	16,001,516	16,846,888	17,056,023	17,409,884	16,993,872	16,282,682
Total RPS Eligible Procurement	549,856	677,852	825,302	899,520	880,777	1,047,441	1,784,441	1,940,129
AnnualProcurementTarget(APT)	296,073	446,511	604,627	764,642	933,111	1,103,671	1,277,770	3,256,536
IncrementalProcurementTarget(IPT)	N/A	150,439	158,116	160,015	168,469	170,560	174,099	1,978,766
Preliminary Procurement Surplus/(Deficit)	253,783	231,341	220,675	134,878	(52,334)	(56,231)	506,670	(1,316,408)

2010 ActualProcurementPercentage	2003	2004	2005	2006	2007	2008	2009	2010
Surplus Procurement Bank Balance as of Prior Year	0	253,783	485,124	705,798	840,677	788,342	732,112	1,238,782
Applicationof Banked Surplus Procurement to Current Year Deficit					(52,334)	(56,231)		(1,316,408)
Adjusted Current Year Annual Surplus Procurement	253,783	231,341	220,675	134,878	0	0	506,670	0
Cumulative Surplus/(Deficit) Procurement Bank Balance Carried into CP1	253,783	485,124	705,798	840,677	788,342	732,112	1,238,782	(77,625)

~~2012 RPS Plan – Need Assessment Workbook~~

~~The workbook below provides the data behind SDG&E's probability weighted need assessment as of May 2012. The following information is provided in each tab:~~

- ~~"Prob Delivering Contracts" tab shows the success rate that SDG&E has applied to each of the delivering contracts in its portfolio.~~
- ~~"Prob Developing Contracts" tab shows the success rate that SDG&E has applied to each of the developing contracts in its portfolio.~~
- ~~"Net Short Calculation" tab show how SDG&E calculates "Net Short" carried into CP1.~~

Renewable Net Short Calculation:

The tables below provide the data behind SDG&E's RPS Risk Adjusted Net Short Calculation as of August, 2012 and includes the outputs required by Administrative Law Judge's Ruling (1) Adopting Renewable Net Short Calculation Methodology (2) Incorporating the Attached Methodology into the Record, and (3) Extended the Date for Filing Updates to 2012

Procurement Plans, dated August 2, 2012. A discussion of this analysis is provided in Section VI below.

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2011 Actuals	2012 Expected	2013 Forecast	CP1 2011-2013	2014 Forecast	2015 Forecast	2016 Forecast	CP2 2014-2016
T		Forecast Year	-	-	1	-	2	3	4	-
A		**Bundled Retail Sales Forecast[1]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	18,074	[redacted]
B		**RPS Procurement Quantity Requirement %**	20.0%	20.0%	20.0%	20.0%	21.7%	23.3%	25.0%	-
C		**RPS Procurement Quantity Requirement**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	4,519	[redacted]
D_a		*Risk-Adjusted Online Generation[2]*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,532	[redacted]
D_b		*Risk-Adjusted Forecast Generation[2]*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3,812	[redacted]
D_c		*Pre-Approved Generic Generation[2]*	-	-	2	2	138	306	483	927
D	$D_a + D_b + D_c$	**Net RPS Position[5]**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
E	D / A	Net RPS Position (% of Retail Sales)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	32.2%	[redacted]
F	D - C	**GWh Gross Surplus (Deficit)**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
G		Banked RECs applied	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
I		All RECs from short-term contracts signed after 6/1/10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]
J		*Limit of Category 3 allowed under statute*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	515	[redacted]
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
M	L - C	**Excess Procurement for CP**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
N	Max $(M_{(T-1)},0) + M_T$	**REC Bank Balance**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	3,966	[redacted]
		Aggregated probability weighted GWh data[3]	-	-	-	-	-	-	-	-
O_a		*High viability (>=85%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	2,998	[redacted]
O_b		*Viable (70-85%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	911	[redacted]
O_c		*High Risk (<70%)*	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,917	[redacted]
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	5,827	[redacted]
P		Aggregate delivery failure rate - new projects[4]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	37.4%	[redacted]
Q		Aggregate delivery failure rate - existing projects[4]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	8.1%	[redacted]
R	A x 1.5%	Voluntary Margin of Overprocurement	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	1,309	[redacted]
S		Voluntary Margin of Overprocurement (implied % of retail sales)	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	7.2%	[redacted]
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	-	[redacted]

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5% ; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5) CP1 total includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2017 Forecast	2018 Forecast	2019 Forecast	2020 Forecast	CP3 2017-2020	2021 Forecast	2022 Forecast	2023 Forecast
T		Forecast Year	5	6	7	8	-	9	10	11
A		**Bundled Retail Sales Forecast[1]**	18,216	18,375	18,578	18,807	73,976	19,014	19,223	19,434
B		RPS Procurement Quantity Requirement %	27.0%	29.0%	31.0%	33.0%	-	33.0%	33.0%	33.0%
C		RPS Procurement Quantity Requirement	4,918	5,329	5,759	6,206	22,213	6,275	6,344	6,413
D_a		*Risk-Adjusted Online Generation[2]*	*1,496*	*1,167*	*1,058*	*890*	***4,611***	*963*	*963*	*868*
D_b		*Risk-Adjusted Forecast Generation[2]*	*3,799*	*3,787*	*3,772*	*3,759*	***15,118***	*3,758*	*3,751*	*3,745*
D_c		*Pre-Approved Generic Generation[2]*	*545*	*545*	*545*	*546*	***2,181***	*546*	*546*	*546*
D	$D_a + D_b + D_c$	**Net RPS Position**	5,840	5,500	5,375	5,195	21,910	5,266	5,260	5,159
E	D / A	Net RPS Position (% of Retail Sales)	32.1%	29.9%	28.9%	27.6%	29.6%	27.7%	27.4%	26.5%
F	D - C	**GWh Gross Surplus (Deficit)**	921	171	(384)	(1,011)	(303)	(1,009)	(1,084)	(1,254)
G		Banked RECs applied	-	-	384	1,011	1,395	1,009	1,084	1,254
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	921	171	0	(0)	1,092	0	0	(0)
I		All RECs from short-term contracts signed after 6/1/10	-	-	-	-	-	-	-	-
J		*Limit of Category 3 allowed under statute*	*349*	*347*	*346*	*345*	***1,387***	*344*	*344*	*343*
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	5,840	5,500	5,375	5,195	21,910	5,178	5,172	5,076
M	L - C	**Excess Procurement for CP**	921	171	(384)	(1,011)	(303)	(1,096)	(1,171)	(1,337)
N	$\max(M_{(T-1)},0) + M_T$	**REC Bank Balance**	4,888	5,059	4,675	3,664	3,664	2,655	1,571	317
		Aggregated probability weighted GWh data[3]	-	-	-	-	-	-	-	-
O_a		*High viability (>=85%)*	*3,021*	*2,689*	*2,576*	*2,569*	-	*2,570*	*2,473*	*2,178*
O_b		*Viable (70-85%)*	*909*	*907*	*904*	*738*	-	*721*	*717*	*714*
O_c		*High Risk (<70%)*	*1,910*	*1,904*	*1,895*	*1,888*	-	*1,887*	*1,886*	*1,886*
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	5,840	5,500	5,375	5,195	-	5,178	5,076	4,778
P		Aggregate delivery failure rate - new projects[4]	37.4%	37.4%	37.3%	37.3%	37.4%	37.3%	37.3%	37.3%
Q		Aggregate delivery failure rate - existing projects[4]	7.9%	7.5%	7.7%	5.2%	7.2%	5.0%	5.0%	5.0%
R	A x 1.5%	Voluntary Margin of Overprocurement	921	171	0	-	1,093	0	0	-
S		Voluntary Margin of Overprocurement (implied % of retail sales)	5.1%	0.9%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	0	-	384	1,011	1,395	1,097	1,268	1,636

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5% ; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5)Includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

SDG&E Residual Net Short for RPS Procurement - August 13, 2012

Variable	Calculation	Item	2024 Forecast	2025 Forecast	2026 Forecast	2027 Forecast	2028 Forecast	2029 Forecast	2030 Forecast	2031 Forecast
T		Forecast Year	12	13	14	15	16	17	18	19
A		**Bundled Retail Sales Forecast[1]**	19,648	19,864	20,083	20,304	20,527	20,753	20,981	21,212
B		**RPS Procurement Quantity Requirement %**	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%	33.0%
C		**RPS Procurement Quantity Requirement**	6,484	6,555	6,627	6,700	6,774	6,848	6,924	7,000
D_a		*Risk-Adjusted Online Generation[2]*	*543*	*232*	*40*	*38*	*38*	*38*	*38*	*18*
D_b		*Risk-Adjusted Forecast Generation[2]*	*3,739*	*3,733*	*3,727*	*3,721*	*3,715*	*3,709*	*3,703*	*3,697*
D_c		*Pre-Approved Generic Generation[2]*	*546*	*534*	*534*	*534*	*534*	*535*	*535*	*535*
D	$D_a + D_b + D_c$	**Net RPS Position**	4,828	4,499	4,301	4,293	4,287	4,282	4,276	4,250
E	D / A	Net RPS Position (% of Retail Sales)	24.6%	22.6%	21.4%	21.1%	20.9%	20.6%	20.4%	20.0%
F	D - C	**GWh Gross Surplus (Deficit)**	(1,656)	(2,057)	(2,326)	(2,407)	(2,487)	(2,567)	(2,648)	(2,750)
G		Banked RECs applied	317	-	-	-	-	-	-	-
H	F + G	**Net Surplus (Deficit) after banked RECs applied**	(1,339)	(2,057)	(2,326)	(2,407)	(2,487)	(2,567)	(2,648)	(2,750)
I		All RECs from short-term contracts signed after 6/1/10	-	-	-	-	-	-	-	-
J		*Limit of Category 3 allowed under statute*	*343*	*341*	*338*	*338*	*337*	*337*	*336*	*336*
K		*Long-term contract deliveries of Category 3 RECs above limit*	-	-	-	-	-	-	-	-
L	D - I - K	**RECs eligible for excess procurement**	4,778	4,479	4,300	4,292	4,286	4,280	4,275	4,250
M	L - C	**Excess Procurement for CP**	(1,706)	(2,076)	(2,328)	(2,408)	(2,488)	(2,568)	(2,649)	(2,750)
N	Max ($M_{(T-1)}$,0) + M_T	**REC Bank Balance**	0	0	0	0	0	0	0	0
		Aggregated probability weighted GWh data[3]	-	-	-	-	-	-	-	-
O_a		*High viability (>=85%)*	*1,882*	*1,705*	*1,700*	*1,697*	*1,694*	*1,691*	*1,668*	*1,354*
O_b		*Viable (70-85%)*	*712*	*710*	*708*	*705*	*703*	*701*	*699*	*697*
O_c		*High Risk (<70%)*	*1,885*	*1,885*	*1,884*	*1,884*	*1,883*	*1,883*	*1,882*	*1,800*
O	$O_a + O_b + O_c = O = D$	Total Risk-Adjusted Generation	4,479	4,300	4,292	4,286	4,280	4,275	4,250	3,851
P		Aggregate delivery failure rate - new projects[4]	37.3%	37.3%	37.3%	37.3%	37.3%	37.4%	37.4%	37.4%
Q		Aggregate delivery failure rate - existing projects[4]	3.5%	2.5%	0.2%	0.2%	0.2%	0.2%	0.2%	0.1%
R	A x 1.5%	Voluntary Margin of Overprocurement	-	-	-	-	-	-	-	-
S		Voluntary Margin of Overprocurement (implied % of retail sales)	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
U	C - O + R	**Annual RPS Risk-adjusted Net Short (Long)**	2,005	2,256	2,336	2,414	2,494	2,574	2,674	3,149

(1) 2011 values are actuals; 2012 actuals include year-to-date actual deliveries with previous year's retail sales for remaining months increased by 2.5%; forecast numbers are based upon LTPP.
(2) Generation figures are net of any renewable sales
(3) Viability categories as discussed in section 1 of RPS plan Section I.B.1.
(4) Delivery failure rate is probability weighted deviation below expected forecast generation, and is based upon but not limited to probability assessments of project failure, project capacity reduction, operational failure after project success, project curtailment due to transmission constraints, etc.
(5)Includes deduction of 77.6 GWh after deficits applied from prior banked procurement (before 2010)

	Contracts Presently Delivering August 13, 2012									Probability Weighted Deliveries									
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Shell	[redacted]		Wind	9/10/09	1.75	4/1/10	12/31/11	104.4	[redacted]									
2	Otay Landfill I	[redacted]		Biogas	5/1/09	10	5/1/09	4/30/19	1.5	[redacted]									
3	Otay Landfill II	[redacted]		Biogas	2/22/11	20	7/1/11	6/30/31	1.5	[redacted]									
4	San Marcos Landfill	[redacted]		Biogas	11/20/09	20	5/18/11	5/17/31	1.5	[redacted]									
5	Sycamore Landfill	[redacted]		Biogas	11/20/09	20	5/16/11	5/15/31	1.5	[redacted]									
6	Badger Filtration Plant	[redacted]		Conduit Hydro	2/28/85	30	7/1/87	6/30/17	1.485	[redacted]									
7	Bear Valley Hydro	[redacted]		Conduit Hydro	4/13/94	Evergreen	4/13/94	Evergreen	1.5	[redacted]									
8	Olivenhain Municipal	[redacted]		Conduit Hydro	9/16/87	Evergreen	11/1/88	Evergreen	0.45	[redacted]									
9	San Francisco Peak Hydro Plant	[redacted]		Conduit Hydro	8/29/85	Evergreen	12/15/85	Evergreen	0.35	[redacted]									
10	MM San Diego Miramar	[redacted]		Biogas	10/31/02	10	5/20/03	4/30/13	3	[redacted]									
11	MM San Diego North City	[redacted]		Biogas	10/31/02	10	5/20/03	4/30/13	1	[redacted]									
12	GRS Coyote Canyon	[redacted]		Biogas	10/31/02	10	1/1/03	12/31/12	6.057	[redacted]									
13	GRS Sycamore	[redacted]		Biogas	10/31/02	10	3/30/04	3/30/14	2.5	[redacted]									
14	MM Prima Deshecha	[redacted]		Biogas	9/6/05	15	10/1/07	9/30/22	12.2	[redacted]									
15	Otay Lanfill 3	[redacted]		Biogas	8/31/05	10	3/8/07	3/7/17	3.375	[redacted]									
16	Blue Lake Power	[redacted]		Biomass	6/9/08	10	4/30/10	4/29/20	11	[redacted]									
17	City of San Diego MWD	[redacted]		Biogas	12/22/06	5	1/1/08	12/31/12	5	[redacted]									
18	Covanta Delano	[redacted]		Biomass	12/21/06	10	1/1/08	12/31/17	49	[redacted]									
19	Kumeyaay	[redacted]		Wind	5/31/04	20	3/21/06	12/30/25	50	[redacted]									
20	Oasis Power Partners	[redacted]		Wind	10/30/02	15	12/31/04	12/30/19	60	[redacted]									
21	Iberdrola Mt Wind	[redacted]		Wind	11/1/02	16	12/15/03	12/31/18	22.8	[redacted]									
22	Iberdrola PWest	[redacted]		Wind	11/1/02	16	12/15/03	12/31/18	2.1	[redacted]									
23	WTE Acquisition (FPL)	[redacted]		Wind	10/31/02	15	6/28/04	12/31/18	16.5	[redacted]									
24	Glacier Wind 1	[redacted]		Wind	5/16/08	15	12/29/08	12/29/23	106.5	[redacted]									
25	Glacier Wind 2	[redacted]		Wind	5/23/08	15	10/16/09	10/16/24	103.5	[redacted]									
26	Coram	[redacted]		Wind	7/15/10	15	2/1/11	1/31/26	7.5	[redacted]									
27	SDCWA Rancho Penasquitos	[redacted]		Conduit Hydro	11/20/03	10	1/23/07	1/22/17	4.5	[redacted]									
28	SDG&E Sustainable Communities	[redacted]		Solar PV	5/30/10	30	5/4/09	5/4/39	0.54	[redacted]									
29	Calpine Geysers	[redacted]		Geothermal	2/26/10	4.833	3/1/10	12/31/14	25	[redacted]									
30	Silicon Valley	[redacted]		Geothermal	6/30/11	1	7/1/11	6/30/12	40	[redacted]									
31	Calpine Geysers	[redacted]		Geothermal	9/22/11	0.25	10/1/11	12/31/11	11.5	[redacted]									
32	Edison	[redacted]		Various	9/22/11	2.3	10/1/11	12/31/13	193	[redacted]									
33	Mesa	[redacted]		Wind	11/2/11	2	4/1/12	12/31/13	30	[redacted]									
34	SDG&E SEP (UOG)	[redacted]		Solar PV	7/11/08	30	1/1/10	1/1/40	17	[redacted]									
35	RAM (To be added)	[redacted]		Solar PV		30	1/1/09	1/1/39	125	[redacted]									
36	FIT (To be added)	[redacted]		Various		20	6/1/12	5/31/32	39.8	[redacted]									
37	Edison 2	[redacted]		Various	3/23/12	0.3	9/1/12	12/31/12	103	[redacted]									
38	Sierra Pacific Industries	[redacted]		Biomass	3/30/12	0	1/0/00	1/0/00	0	[redacted]									
39	Cabazon	[redacted]		Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]									
40	Whitewater	[redacted]		Wind	7/3/12	2	1/1/12	12/31/13	0	[redacted]									

Contracts Presently Delivering August 13, 2012										Probability Weighted Deliveries										
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Shell	[redacted]		Wind	9/10/09	1.75	4/1/10	12/31/11	104.4	[redacted]										
2	Otay Landfill I			Biogas	5/1/09	10	5/1/09	4/30/19	1.5											
3	Otay Landfill II			Biogas	2/22/11	20	7/1/11	6/30/31	1.5											
4	San Marcos Landfill			Biogas	11/20/09	20	5/18/11	5/17/31	1.5											
5	Sycamore Landfill			Biogas	11/20/09	20	5/16/11	5/15/31	1.5											
6	Badger Filtration Plant			Conduit Hydro	2/28/85	30	7/1/87	6/30/17	1.485											
7	Bear Valley Hydro			Conduit Hydro	4/13/94	Evergreen	4/13/94	Evergreen	1.5											
8	Olivenhain Municipal			Conduit Hydro	9/16/87	Evergreen	11/1/88	Evergreen	0.45											
9	San Francisco Peak Hydro Plant			Conduit Hydro	8/29/85	Evergreen	12/15/85	Evergreen	0.35											
10	MM San Diego Miramar			Biogas	10/31/02	10	5/20/03	4/30/13	3											
11	MM San Diego North City			Biogas	10/31/02	10	5/20/03	4/30/13	1											
12	GRS Coyote Canyon			Biogas	10/31/02	10	1/1/03	12/31/12	6.057											
13	GRS Sycamore			Biogas	10/31/02	10	3/30/04	3/30/14	2.5											
14	MM Prima Deshecha			Biogas	9/6/05	15	10/1/07	9/30/22	12.2											
15	Otay Lanfill 3			Biogas	8/31/05	10	3/8/07	3/7/17	3.375											
16	Blue Lake Power			Biomass	6/9/08	10	4/30/10	4/29/20	11											
17	City of San Diego MWD			Biogas	12/22/06	5	1/1/08	12/31/12	5											
18	Covanta Delano			Biomass	12/21/06	10	1/1/08	12/31/17	49											
19	Kumeyaay			Wind	5/31/04	20	3/21/06	12/30/25	50											
20	Oasis Power Partners			Wind	10/30/02	15	12/31/04	12/30/19	60											
21	Iberdrola Mt Wind			Wind	11/1/02	16	12/15/03	12/31/18	22.8											
22	Iberdrola PWest			Wind	11/1/02	16	12/15/03	12/31/18	2.1											
23	WTE Acquisition (FPL)			Wind	10/31/02	15	6/28/04	12/31/18	16.5											
24	Glacier Wind 1			Wind	5/16/08	15	12/29/08	12/29/23	106.5											
25	Glacier Wind 2			Wind	5/23/08	15	10/16/09	10/16/24	103.5											
26	Coram			Wind	7/15/10	15	2/1/11	1/31/26	7.5											
27	SDCWA Rancho Penasquitos			Conduit Hydro	11/20/03	10	1/23/07	1/22/17	4.5											
28	SDG&E Sustainable Communities			Solar PV	5/30/10	30	5/4/09	5/4/39	0.54											
29	Calpine Geysers			Geothermal	2/26/10	4.833	3/1/10	12/31/14	25											
30	Silicon Valley			Geothermal	6/30/11	1	7/1/11	6/30/12	40											
31	Calpine Geysers			Geothermal	9/22/11	0.25	10/1/11	12/31/11	11.5											
32	Edison			Various	9/22/11	2.3	10/1/11	12/31/13	193											
33	Mesa			Wind	11/2/11	2	4/1/12	12/31/13	30											
34	SDG&E SEP (UOG)			Solar PV	7/11/08	30	1/1/10	1/1/40	17											
35	RAM (To be added)			Solar PV		30	1/1/09	1/1/39	125											
36	FIT (To be added)			Various		20	6/1/12	5/31/32	39.8											
37	Edison 2			Various	3/23/12	0.3	9/1/12	12/31/12	103											
38	Sierra Pacific Industries			Biomass	3/30/12	0	1/0/00	1/0/00	0											
39	Cabazon			Wind	7/3/12	2	1/1/12	12/31/13	0											
40	Whitewater			Wind	7/3/12	2	1/1/12	12/31/13	0											

	Contracts Presently Developing August 13, 2012									Probability Weighted Deliveries									
	Name	CP1 Prob ability	CP2&3 Prob ability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Centinela	[redacted]		Solar PV	5/10/10	20	4/1/14	3/31/34	125	[redacted]									
2	Centinela 2	[redacted]		Solar PV	7/29/10	20	9/1/14	8/31/34	30	[redacted]									
3	Rim Rock	[redacted]		Wind	5/5/09	20	10/1/12	9/30/32	189	[redacted]									
4	Pattern	[redacted]		Wind	2/1/11	20	12/15/12	12/15/33	265	[redacted]									
5	Pacific Wind	[redacted]		Wind	10/14/05	20	8/31/12	8/30/32	140	[redacted]									
6	Solargen2	[redacted]		Solar PV	6/24/11	25	9/30/12	9/29/37	150	[redacted]									
7	enXco Catalina	[redacted]		Solar PV	6/3/11	25	6/30/13	6/30/38	110	[redacted]									
8	Alta Mesa	[redacted]		Wind	12/17/09	20	3/1/12	2/28/32	40	[redacted]									
9	Arlington	[redacted]		Solar PV	6/3/11	25	12/20/13	12/19/38	127	[redacted]									
10	ESJ	[redacted]		Wind	4/6/11	20	8/31/13	12/31/33	150	[redacted]									
11	NRG Borrego	[redacted]		Solar PV	1/25/11	25	7/31/12	7/31/37	26	[redacted]									
12	Sol Orchard	[redacted]		Solar PV	4/11/11	25	12/31/12	12/30/37	50	[redacted]									
13	MMR Campo Verde	[redacted]		Solar PV	11/10/06	20	9/30/13	9/29/33	139	[redacted]									
14	Tenaska South	[redacted]		Solar PV	11/10/10	25	1/1/14	1/1/39	130	[redacted]									
15	Victor Mesa Linda B	[redacted]		Solar PV		20	10/31/13	10/31/33	5	[redacted]									
16	Western Antelope Dry Ranch	[redacted]		Solar PV		20	10/31/13	10/31/33	10	[redacted]									
17	Soitec TDS	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	45	[redacted]									
18	Soitec Rugged	[redacted]		Solar PV	5/17/11	25	12/31/14	12/30/39	80	[redacted]									
19	Campo (Shuu'luk)	[redacted]		Wind		25	10/1/14	9/30/39	160	[redacted]									
20	Tenaska West	[redacted]		Solar PV	3/8/11	25	1/1/16	12/31/40	140	[redacted]									
21	Soitec Desert Green	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]									
22	Soitec Eastland	[redacted]		Solar PV	3/31/11	25	10/31/14	10/30/39	20	[redacted]									
23	Soitec Westland	[redacted]		Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]									
24	Manzana	[redacted]		Wind	2/14/12	20	10/31/12	6/30/32	100	[redacted]									
25	AES Mt Signal 1 Solar	[redacted]		Solar PV	2/10/12	25	5/31/13	6/29/38	200	[redacted]									
26	Otay Landfill V CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]									
27	Otay Landfill VI CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]									
28	Otay Landfill VII CRE (FIT)	[redacted]		Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]									
29	Mushroom Power CRE (FIT)	[redacted]		Biomass	12/12/11	20	10/1/12	9/30/32	1.5	[redacted]									
30	BAP Power CRE (FIT)	[redacted]		Solar PV	12/13/11	20	9/1/12	8/31/32	1.5	[redacted]									
31	Descanso Solar CRE (FIT)	[redacted]		Solar PV	12/27/11	20	7/15/13	7/14/33	1.5	[redacted]									

Contracts Presently Developing August 13, 2012										Probability Weighted Deliveries										
	Name	CP1 Probability	CP2&3 Probability	Technology	Date Signed	Term (yrs)	Start	Stop	Capacity (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
1	Centinela	[redacted]	[redacted]	Solar PV	5/10/10	20	4/1/14	3/31/34	125	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2	Centinela 2	[redacted]	[redacted]	Solar PV	7/29/10	20	9/1/14	8/31/34	30	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
3	Rim Rock	[redacted]	[redacted]	Wind	5/5/09	20	10/1/12	9/30/32	189	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
4	Pattern	[redacted]	[redacted]	Wind	2/1/11	20	12/15/12	12/15/33	265	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
5	Pacific Wind	[redacted]	[redacted]	Wind	10/14/05	20	8/31/12	8/30/32	140	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
6	Solargen2	[redacted]	[redacted]	Solar PV	6/24/11	25	9/30/12	9/29/37	150	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
7	enXco Catalina	[redacted]	[redacted]	Solar PV	6/3/11	25	6/30/13	6/30/38	110	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
8	Alta Mesa	[redacted]	[redacted]	Wind	12/17/09	20	3/1/12	2/28/32	40	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
9	Arlington	[redacted]	[redacted]	Solar PV	6/3/11	25	12/20/13	12/19/38	127	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
10	ESJ	[redacted]	[redacted]	Wind	4/6/11	20	8/31/13	12/31/33	150	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
11	NRG Borrego	[redacted]	[redacted]	Solar PV	1/25/11	25	7/31/12	7/31/37	26	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
12	Sol Orchard	[redacted]	[redacted]	Solar PV	4/11/11	25	12/31/12	12/30/37	50	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
13	MMR Campo Verde	[redacted]	[redacted]	Solar PV	11/10/06	20	9/30/13	9/29/33	139	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
14	Tenaska South	[redacted]	[redacted]	Solar PV	11/10/10	25	1/1/14	1/1/39	130	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
15	Victor Mesa Linda B	[redacted]	[redacted]	Solar PV		20	10/31/13	10/31/33	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
16	Western Antelope Dry Ranch	[redacted]	[redacted]	Solar PV		20	10/31/13	10/31/33	10	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
17	Soitec TDS	[redacted]	[redacted]	Solar PV	5/17/11	25	12/31/14	12/30/39	45	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
18	Soitec Rugged	[redacted]	[redacted]	Solar PV	5/17/11	25	12/31/14	12/30/39	80	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
19	Campo (Shuu'luk)	[redacted]	[redacted]	Wind		25	10/1/14	9/30/39	160	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
20	Tenaska West	[redacted]	[redacted]	Solar PV	3/8/11	25	1/1/16	12/31/40	140	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
21	Soitec Desert Green	[redacted]	[redacted]	Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
22	Soitec Eastland	[redacted]	[redacted]	Solar PV	3/31/11	25	10/31/14	10/30/39	20	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
23	Soitec Westland	[redacted]	[redacted]	Solar PV	3/31/11	25	2/28/14	2/27/39	5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
24	Manzana	[redacted]	[redacted]	Wind	2/14/12	20	10/31/12	6/30/32	100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
25	AES Mt Signal 1 Solar	[redacted]	[redacted]	Solar PV	2/10/12	25	5/31/13	6/29/38	200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
26	Otay Landfill V CRE (FIT)	[redacted]	[redacted]	Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
27	Otay Landfill VI CRE (FIT)	[redacted]	[redacted]	Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
28	Otay Landfill VII CRE (FIT)	[redacted]	[redacted]	Landfill gas	12/27/11	20	6/27/13	6/26/33	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
29	Mushroom Power CRE (FIT)	[redacted]	[redacted]	Biomass	12/12/11	20	10/1/12	9/30/32	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
30	BAP Power CRE (FIT)	[redacted]	[redacted]	Solar PV	12/13/11	20	9/1/12	8/31/32	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
31	Descanso Solar CRE (FIT)	[redacted]	[redacted]	Solar PV	12/27/11	20	7/15/13	7/14/33	1.5	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

VI. "MINIMUM MARGIN" OF PROCUREMENT- -§ 399.13(A)(4)(D)

~~SDG&E's minimum margin of procurement for Compliance Period 1 is the difference between its RPS goals and the probability weighted deliveries for Compliance Period 1 as shown in Table 1 above. The minimum margin of procurement for Compliance Period 2, assuming no excess procurement is banked in Compliance Period 1, the difference between the RPS goals and the probability weighted deliveries for Compliance Period 2 as shown in Table 1 above. The minimum margin of procurement for Compliance Period 3, again assuming no excess procurement is banked in Compliance Period 1, is the difference between the RPS goals and the probability weighted deliveries for Compliance Period 3 as adjusted by the excess procurement bank from Compliance Period 2. The table below summarizes SDG&E's minimum margin of procurement for each compliance period.~~

~~**Compliance Period**~~	~~**RPS Target (GWh)**~~	~~**Probability Weighted Deliveries (GWh)**~~	~~**Banked Procurement from Previous Compliance Period**~~	~~**Minimum Margin of Procurement**~~
~~1~~	[redacted]			
~~2~~				
~~3~~	~~23,202~~	[redacted]		

~~If SDG&E holds a solicitation in 2012, it anticipates that it would incorporate the following procurements needs.~~

- ~~Compliance Period 1: SDG&E would shortlist 150% of its minimum margin of procurement in anticipation that not all shortlisted projects will either accept their position on the shortlist or come online.~~
- ~~Compliance Period 2: SDG&E does not expect to have procurement need for Compliance Period 2.~~
- ~~Compliance Period 3: SDG&E would divide its minimum margin of procurement by three in order to avoid over procurement and potential exposure to long term market risk. It would then shortlist 150% of this number in anticipation that not all shortlisted projects will either accept their position on the shortlist or come online.~~

SDG&E's RPS Risk Adjusted Net Short Calculation, as shown in Section V above, provides a "Minimum Margin of Procurement" that is intended to account for foreseeable project failures or delay. This calculation also includes an additional "Voluntary Margin of Over-Procurement", which is intended to ensure that SDG&E achieves its RPS requirements despite unforeseeable risks. Since both the RPS targets and RPS deliveries fluctuate constantly, it is nearly impossible to meet RPS targets with the exact number of MWhs required. SDG&E's Voluntary Margin of Over-Procurement is designed to ensure that it achieves its RPS goals with a "buffer" to account for unforeseen changes to either the RPS targets or deliveries. Because it is more difficult to predict retail sales and project performance in CP2 and CP3, SDG&E's Voluntary Margin of Over-Procurement is higher in those years. SDG&E's RNS calculation, including its Voluntary Margin of Over-Procurement, for each compliance period is described below.

A. Compliance Period 1

SDG&E's Compliance Period 1 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 1 RPS percentage target plus the deficit that SDG&E is required to carry forward from the prior RPS regime as discussed in Section I(B)(2)(g) of SDG&E's 2012 RPS Plan.
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP1
- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan
- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

B. Compliance Period 2

SDG&E's Compliance Period 2 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 2 RPS percentage target
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP2
- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan
- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

C. Compliance Period 3

SDG&E's Compliance Period 3 RNS is based on the following formula:

> RPS Risk-adjusted Net Short = (Bundled Retail Sales Forecast x RPS Procurement Quantity Requirement+ Voluntary Minimum Margin of Procurement) – (Online Generation + Risk-adjusted Forecast Generation + Pre-approved Generic Generation)

Where:

- Bundled Retails Sales Forecast = the forecast developed in accordance with Section I(B)(2)(a) SDG&E's 2012 RPS Plan
- RPS Procurement Quantity Requirement = Compliance Period 3 RPS percentage target
- Voluntary Minimum Margin of Procurement = up to the current anticipated net long position for CP3
- Online Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have achieved commercial operation, as discussed in Section I(B)(1)(a) of SDG&E's 2012 RPS Plan

- Risk-adjusted Forecast Generation = the generation that SDG&E expects will be delivered by its portfolio of RPS projects that have not yet achieved commercial operation, as discussed in Section I(B)(1)(b) of SDG&E's 2012 RPS Plan
- Pre-approved Generic Generation = unsubscribed volumes that SDG&E is required to procure under CPUC programs such as the Renewable Auction Mechanism and the Feed-in-Tariff

VII. BID SOLICITATION PROTOCOL, INCLUDING LCBF METHODOLOGIES - § 399.13(A)(5)(C) AND D.04-07-029

Attached are SDG&E's proposed bid solicitation protocol and related documents for a 2012 RPS solicitation (2012 RPS RFO).

- Appendix A: 2012 RPS Solicitation (RFO Document)
- Appendix B1: 2012 RFO Participation Summary
- Appendix B2: 2012 RFO Project Description Form
- Appendix B3: 2012 RFO Bundled Pricing Form
- Appendix B4: 2012 RFO REC Pricing Form
- Appendix B5: 2012 RFO Model PPA
- Appendix B6: 2012 RFO REC Agreement
- Appendix B7: 2012 RFO Credit Application
- Appendix B8: 2012 RFO Consent Form
- Appendix C: Evaluation Methodology (LCBF Process)

~~VIII~~VIII. ESTIMATING TRANSMISSION COST FOR THE PURPOSE OF RPS PROCUREMENT AND BID EVALUATION - TRANSMISSION RANKING COST REPORT REQUIRED

SDG&~~E's TRCR is being completed by its Transmission Planning Department and is expected be~~E filed a draft TRCR on June 26, 2012.

IX. CONSIDERATION OF PRICE ADJUSTMENT MECHANISMS -§ 399.13(A)(5)(E)

SDG&E acknowledges that contracts with online dates occurring more than 24 months after the contract execution date can pose additional risk to ratepayers. SDG&E has incorporated price adjustment mechanisms in some of its current contracts that are intended to alleviate some of these risks, including the following:

SB_GT&S_0561885

- Price adjustment for delay in Guaranteed Commercial Operation Date ("GCOD"): A lower price for a late GCOD provides additional incentive for developers to come online as early as possible. However, this structure can create financing challenges if financing parties are not comfortable with the potentially lower price. It is also difficult to quantify an appropriate price adjustment amount and can lead to drawn out negotiations.
- Capped transmission upgrade costs: Placing a cap on the amount of transmission upgrade costs, which are ultimately borne by ratepayers, that a project can bear is an important way to limit ratepayer exposure to such costs. This type of cap is especially important for projects with CODs more than 24 months after the contract execution date because it is unlikely that such projects have received reliable transmission upgrade cost estimates at the time the contract is signed.

SDG&E also proposes a revised security provision that is intended to alleviate the risk of a long period between execution and construction. The Construction Period Security should escalate in proportion to the duration of time between contract execution and start of construction. For example:

- For Projects with a construction start date within 12 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $20
- For Projects with a construction start date within 24 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $30
- For Projects with a construction start date within 36 months of Execution of the agreement - 2X the annual estimated deliveries of energy (MWh) X $40

SDG&E believes that this security structure will help to protect ratepayers from the risk that developers have improperly assessed turbine or panel prices. The longer the developer must wait to buy turbines/panels, the more risk exists that the prices will go up and the developer will not be able to develop the project for the price offered. The additional security would help to protect against this increased market risk.

X. COST QUANTIFICATION TABLE

1	Technology Type	Actual RPS Eligible Procurement and Generation Costs 2003	2004	2005	2006	2007	2008	2009	2010	2011
2	Biogas	6,201,139	8,541,291	8,915,866	8,087,169	6,685,347	9,388,536	10,067,817	11,383,663	10,699,119
3	Biomass	18,888,387	18,693,045	17,205,462	16,965,465	12,237,997	22,995,311	24,605,914	27,430,655	27,275,365
4	Geothermal	0	0	0	0	0	0	0	14,679,414	29,437,292
5	Small Hydro	0	0	0	0	994,116	1,210,445	1,035,376	1,036,066	776,149
6	Solar PV	0	0	0	0	0	0	0	0	8,411,735
7	Solar Thermal	0	0	0	0	0	0	0	0	0
8	Wind	22,750	5,980,963	14,097,259	19,779,696	22,968,510	22,131,340	60,255,477	54,744,756	66,266,623
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0
11	RECs (incl. any buy/sell back	0	0	0	0	0	0	0	0	0
12	**Total CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 2 through 11]	**25,112,276**	**33,215,299**	**40,218,587**	**44,832,330**	**42,885,970**	**55,725,632**	**95,964,584**	**109,274,554**	**142,866,283**
13	Bundled Retail Sales (kWh	15,043,865,000	15,811,591,000	16,001,516,000	16,846,888,000	17,056,023,000	17,409,884,000	16,993,872,000	16,282,682,000	16,249,031,000
14	**Incremental Cost per kWh (cents/kWh)**	0.167	0.210	0.251	0.266	0.251	0.320	0.565	0.671	0.879

* Incremental Cost per kWh Impact is equal to Row 12 divided by Row 13, that is, it is defined as the identified costs (Row 12) divided by bundled retail sales (Row 13). While the item is labeled "Incremental Cost per kWh Impact", the value does not constitute a rate impact and should be interpreted as an estimate of a system average cost per kWh for RPS-eligible procurement and generation, not a renewable "premium". In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

1	Executed But Not CPUC Approved RPS Eligible Contracts	Forecasted Future Expenditures on RPS Eligible Procurement and Generation Costs 2012	2013	2014	2015	2016	2017	2018	2019	2020
2	Biogas	0	0	0	0	0	0	0	0	0
3	Biomass	0	0	0	0	0	0	0	0	0
4	Geotherma	22,800,000	0	0	0	0	0	0	0	0
5	Small Hydro	0	0	0	0	0	0	0	0	0
6	Solar PV	33,809,910	94,656,947	110,616,543	109,831,204	108,681,105	107,740,489	107,181,999	105,901,966	105,005,713
7	Solar Thermal	0	0	0	0	0	0	0	0	0
8	Wind	14,140,000	28,765,000	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644	37,811,644
9	UOG Small Hydro	0	0	0	0	0	0	0	0	0
10	UOG Solar	0	0	0	0	0	0	0	0	0
11	RECs (incl. any buy/sell back	280,500	0	0	0	0	0	0	0	0
12	**Total Executed But Not CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 2 through 11]	**71,030,410**	**123,421,947**	**148,428,187**	**147,642,848**	**146,492,749**	**145,552,133**	**144,993,643**	**143,713,610**	**142,817,356**
13	Bundled Retail Sales (kWh	[redacted]	[redacted]	[redacted]	[redacted]	18,595,626,000	18,873,220,000	19,154,172,000	19,454,994,000	19,759,758,000
14	**Incremental Cost per kWh (cents/kWh)**	[redacted]	[redacted]	[redacted]	[redacted]	0.788	0.771	0.757	0.739	0.723

15	CPUC Approved RPS Eligible Contracts (Incl. RAM/FIT/PV Contracts)	2012	2013	2014	2015	2016	2017	2018	2019	2020
16	Biogas	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750	8,711,750
17	Biomass	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321	27,864,321
18	Geothermal	52,128,755	52,128,755	24,217,020	0	0	0	0	0	0
19	Small Hydro	994,116	994,116	994,116	994,116	994,116	994,116	994,116	994,116	994,116
20	Solar PV	34,764,385	97,039,334	240,827,532	296,677,387	356,497,175	355,897,471	355,306,603	354,724,559	354,151,239
21	Solar Thermal	0	0	0	0	0	0	0	0	0
22	Wind	60,751,078	97,495,476	240,312,652	242,204,900	243,761,852	245,558,959	247,769,662	249,291,509	251,294,499
23	UOG Small Hydro	0	0	0	0	0	0	0	0	0
24	UOG Solar	0	0	0	0	0	0	0	0	0
25	RECs (incl. any buy/sell back	0	0	0	0	0	0	0	0	0
26	**CPUC Approved RPS Eligible Procurement and Generation Cost ($)** [Sum of Rows 16 through 25]	**185,214,405**	**284,233,752**	**542,927,391**	**576,452,474**	**637,829,213**	**639,026,617**	**640,646,452**	**641,586,254**	**643,015,925**
27	Bundled Retail Sales (kWh	[redacted]	[redacted]	[redacted]	[redacted]	18,595,626,000	18,873,220,000	19,154,172,000	19,454,994,000	19,759,758,000
28	**Incremental Cost per kWh (cents/kWh)**	[redacted]	[redacted]	[redacted]	[redacted]	3.430	3.386	3.345	3.298	3.254
29	**Total Cost per kWh (cents/kWh) (14+28)**	[redacted]	[redacted]	[redacted]	[redacted]	4.218	4.157	4.102	4.036	3.977

* Incremental Cost per kWh Impact is equal to a Total Cost (either Row 12 or 26) divided by Bundled Retail Sales (either Row 13 or 27). While the item is labeled "Incremental Cost per kWh Impact", the value does not constitute a rate impact and should be interpreted as an estimate of a system averagecost per kWh for RPS-eligible procurement and generation, not a renewable "premium". In other words, the amount shown captures the total cost of the renewable generation and not the additional cost incurred by receiving renewable energy instead of an equivalent amount of energy from conventional generation sources.

XI. IMPORTANT CHANGES TO PLANS NOTED

See Appendix D: Important Plan Changes from 2012 RPS Plan to the 2011 RPS Plan

XII. REDLINED COPY OF PLANS REQUIRED

See Appendix E: Provides redlined version of each of the documents above to show all changes that have been made to the 2011 version of the RPS Plan.

XIII. STANDARDIZED VARIABLES IN LCBF MARKET VALUATION

The proposed Net Market Value calculation differs only slightly from SDG&E's current bid evaluation methodology and SDG&E is not opposed to incorporating the proposed method. The most important issue will be determining what value to use for the Capacity Value. SGD&E submits that the Market Price Referent is the most appropriate value to use.

A renewable energy resource is assigned a capacity value based upon the amount of new generating capacity that would otherwise have to be built to meet SDG&E's needs if the renewable energy resource were not built or would not otherwise displace the need to build new generation facilities. At present, SDG&E values this capacity through the Deliverability Value. This is calculated from the project-specific Market Price Referent with SDG&E's "all-in" TOD factors, less the project-specific Market Price Referent computed with SDG&E's "energy-only" TOD factors, with modifications to prevent negative capacity values in any given TOD period. This is done in order to maintain consistency with SDG&E's "all-in" TOD factors, which were designed to incorporate the effects of capacity value in TOD periods. The MPR itself is computed from the cost of a newly-built gas-fired power plant using publicly-available cost information. The Market Price Referent represents the levelized price, calculated using a cash flow modeling approach, at which the proxy CCGT revenues exactly equal the expected proxy CCGT costs on a net-present value (NPV) basis. The fixed and variable components of the MPR are calculated iteratively and then summed to produce an all-in MPR price. The MPR Model inputs include installed capital costs, fixed and variable operations and maintenance costs, natural gas fuel costs, cost of capital, and environmental permitting and compliance costs.

The main advantage of using the MPR Model over other production cost models or capacity valuation methods is that it is based upon cost and operating inputs that are publicly available, well documented, and familiar to both public and private participants. It relies upon forward costs of natural gas, CEC estimates of operating costs, and historically known plant construction costs updated with econometric indices. Furthermore, since it is based upon a conventional resource, and conventional resources are known to provide the maximum capacity benefits to a bulk power system, it is a reasonably good measurement of capacity value. As a generic model, however, it cannot address location-specific issues of individual generators. It also cannot be used to compare the renewable resources to other renewable resources, as it is based upon a conventional resource.

A summary of the pros and cons of using the MPR model is set forth below.

Pros	Cons
Well known in the California and transparent to IOU's and CA Market participants	The MPR does not address portfolio fit, but rather non-location specific value.
Ensure the same approach among 3 IOUs	The MPR reflects the cost of a natural gas-fired facility, which is not directly comparable to the cost of a renewable resource
Continuity and transparency of the LCBF process	The complexity behind MPR derivation is more complex than the valuation methodology

XIV. PRELIMINARY INDEPENDENT EVALUATOR REPORT

The ACR solicits comments regarding the strengths and weaknesses of a proposal to require the portion of the Preliminary Independent Evaluator Report evaluating bid solicitation materials and LCBF methodology to be submitted as part of the proposed RPS Procurement Plan. SDG&E notes that it already collaborates with its Independent Evaluator regarding its RPS Procurement Plan and that the proposal to formalize what is currently a routine process is not necessary and will compromise efficiency. While this proposal may have potential benefits, the drawbacks of possible usage of the information by potential bidders for gaming purposes as well as the premature nature of the report outweigh these benefits. The IE should be able to recommend process improvements candidly and confidentially throughout the process and up to bid evaluation. A summary of the pros and cons of this proposal is set forth below.

Pros	Cons
ffi The IE can formally ensure that the LCBF criteria explanation will foster maximum participation while discouraging gaming. ffi By addressing the LCBF twice, the	ffi The optimal time for recommendations is after the evaluation is complete so that the full effect of the LCBF can be considered. ffi Requiring the IE to explain in great detail how the LCBF criteria are used in bid

CPUC will be able to see how well the evaluation reflected the set of bids received.	evaluation could be conducive to bid gaming. ffi The proposed process will be circular and administratively cumbersome. It requires the submittal of a finalized plan and associated documents to the IE for comment, after which it must again be revised, all within what it typically a very tight timeline. ffi It is much more efficient and timely to work with the IE throughout the process – as is standard practice – rather than to work independently and combine comments at the end.

XV. USE CAISO TRANSMISSION COST STUDY ESTIMATES IN LCBF EVALUATIONS

Phase II study estimates and estimates performed in feasibility and system impact studies in areas outside CAISO are considered the most accurate and complete set of information regarding project-specific costs. However, they rely upon a time-consuming study process where project bidders within the CAISO must apply for interconnection and frequently wait for two to three years for a final study. The limited and focused scope of the Phase II study is considered confidential information for the project developer. Also, the inability to use non-public transmission information limits the usability of these studies for general public discussion and makes them impractical for routine hypothetical cost estimates of projected future "generic" resources.

The TRCR method provides for a publicly available method of estimating transmission interconnection costs, but is of questionable value. The TRCR method is intended to provide a broad cluster-level overview of interconnection costs and does not provide estimates of costs for project-specific upgrades that are not anticipated within the TRCR study.

Another drawback of the TRCR system is that it does not provide estimates of distribution-level network upgrades (which are typically provided in project-specific SGIP/WDAT studies or Rule 21 interconnection studies). It also does not cover most areas outside of the CAISO that do not deliver to a CAISO delivery point. For such non-CAISO projects, there are no estimates of interconnection costs other than those studies performed by the non-CAISO transmission operator.

SDG&E has used a both sources of data in past RFOs, with study-level data being used where available and TRCR data being used where it was not. While SDG&E believes that this approach has produced fair results in the past, this method could unfairly bias the evaluation process in favor of projects with CAISO study data. Evaluating all projects using TRCR data would solve this potential problem, but could create a disadvantage for developers who have Phase II study results that estimate lower upgrade costs than the TRCR study shows. In addition, projects with Phase II studies are likely to have a viability advantage over projects which have not filed for interconnection or have not filed early enough to receive interconnection study results. SDG&E believes that a hybrid approach is the most sensible overall approach to the problem of transmission upgrade cost estimation in a competitive evaluation. SDG&E suggests that its initial evaluation be based solely on TRCR data. Once it has established a shortlist, however, SDG&E should be able to evaluate any additional transmission cost data that the developer provides, including Phase II studies, to ensure that it has selected the appropriate projects.

Projects with existing interconnections should not have any upgrade costs assigned, unless the project is a repower or expansion of existing facilities or otherwise requires modifications to an existing interconnection to meet new standards.

A summary of the pros and cons of this proposal is set forth below.

TRCR only	
Pro	Con

ffi Public source of cost information - does not require confidentiality ffi Can be used for any project, whether inside or outside of queue process ffi Can be used for hypothetical transmission-connected projects	ffi Cluster level cost data only, cannot be used for precise project-level cost estimates ffi Does not include costs for PTO interconnection or distribution-level upgrades ffi Not a legally binding cost estimate - may lead to unreasonable expectations in negotiating process ffi Can impair fair evaluation of projects with cost studies ffi Does not cover non-CAISO projects

CAISO/PTO studies only	
Pro	Con
ffi Specific project-level determination of required upgrades and associated costs ffi Includes interconnection and distribution-level upgrade costs (through SGIP/WDAT) where applicable ffi Costs under interconnection agreements cannot exceed costs in studies under CAISO tariff (at present)	ffi Long lead time - may require 2-3 years of waiting before available ffi Study results are provided to developer and are considered confidential ffi Impractical for hypothetical projects ffi Can impair fair evaluation of projects without cost studies

Hybrid approach	
Pro	Con
ffi Provides most comprehensive set of information from which projects can be evaluated	ffi Results of CAISO studies do not always correlate with TRCR due to differing study scope ffi Does not provide information on projects at distribution-level which have not completed SGIP/WDAT or Rule 21 interconnection studies

XVI. CREATE TWO SHORTLISTS BASED ON STATUS OF TRANSMISSION STUDY

The ACR proposes that IOUs create Primary and Provisional shortlists. Projects on the Primary shortlist will have obtained CAISO GIP Phase II study results or equivalent, or executed Interconnection Agreements. The Provisional shortlist will contain projects that do not qualify as Primary. To encourage competition, it should be clarified that projects on the Primary shortlist should be permitted to lower their prices at any time. Additionally, timing must be considered in relation to pricing. If there are two projects with the same COD, but with different costs (higher on Primary list, and lower on Provisional list), IOUs should not be required to prematurely procure the more expensive Primary list project without knowing if the Provisional project is able to move to the Primary list. IOU's should also be able to begin working on PPAs with projects on the Primary shortlist regardless of the status of projects on the Provisional shortlist. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi The Provisional "Wait List" will encourage competition. ffi The two lists will inform procurement decisions by providing a pre-approved list of projects that are both viable and cost recoverable, and a pre-approved	ffi This proposal is unclear in regards to the relationship between pricing and timing between the two shortlists. ffi This proposal is unclear as to how the status of projects on the Provisional shortlist may affect

pipeline of projects that are able to move into this first category. ffi The two lists will offer insight into the procurement landscape by showing what types of projects are viable and available.	those on the Primary shortlist.

XVII. SHORTLISTS EXPIRE AFTER 12 MONTHS

The ACR proposes that shortlisted bids be executed within 12 months from the day that the IOU submits its final shortlist (consisting of both Primary and Provisional bids) to the Commission for approval. SDG&E is generally in favor of this approach. In order to discourage the incentive for either party to stall negotiations in order to let the clock expire, the Commission should emphasize that both parties are obligated to negotiate in good faith for the 12 month period. The 12 month limit should not apply to PPAs for projects in which the utility intends to invest. These PPAs are associated with larger transactions (equity contribution agreements) that typically take longer that one year to negotiate. If such a project is solicited through an RFO process, it should not be subject to this limitation. Since the prices for such PPAs are typically based on actual costs plus a negotiated rate of return, it is less likely that the longer negotiation period will result in a mismatch between the contract price and the market. Therefore, excluding these contracts from the 12 month limit should not increase the risk of such a mismatch. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi Decreases risk that the market will change drastically between the time the project is shortlisted and when the contract is signed. At the end of 12 months, if the market has shifted so that the contract price is no longer competitive, the project would have to bid into the next RFO and compete against current market prices.	ffi Does not totally eliminate the risk that the market will change drastically between the time the project is shortlisted and when the contract is signed. For example, contracts that SDG&E initially evaluated in mid 2010 had to be re-evaluated in early 2011 when it became clear that solar panel prices had drastically declined. Could create a perverse incentive to stall

ffi Provides clarity to the market. If the two-tiered shortlist approach is adopted, the 12 month cutoff provides more certainty to provisionally shortlisted bidders with whom SDG&E has not initiated negotiations. If SDG&E does not initiate negotiations within 12 months, the provisionally shortlisted bidders would be released from such shortlist and free to re-bid their projects.	negotiations. If the developer sees that market prices are trending upward, it might chose to stall in order to get out of the deal which is bound by the original bid price. Conversely, if the utility sees that market prices are trending down, it might feel obligated to discontinue negotiations in order to force the developer to bid the project into the next RFO at a lower price.

XVIII. TWO-YEAR PROCUREMENT AUTHORIZATION

SDG&E believes that a 2-year procurement authorization cycle would benefit the procurement process by allowing utilities to procure more efficiently. Instead of holding annual solicitations, even when the utility does not foresee a near term need, the utility could schedule its solicitations within the 2-year period in accordance with its projected need. As the utilities approach compliance with RPS goals, even based on probability weighted deliveries from existing projects, annual solicitations may no longer make sense. As discussion in Section VI above, utilities must procure additional resources above the compliance target based on probability weighted expectations of performance from existing contracts. When the utility has met this probability weighted need for a certain compliance period, the utility should not solicit additional projects that will deliver large volumes during such compliance period. Doing so would send inappropriate signals to the market and distract developers with the fruitless task of preparing a proposal for a project that has little to no chance of being selected. Instead, the Commission should authorize the utility to potentially hold RFO only every other year. In between RFOs, the utility would monitor the performance of its existing portfolio, progress of projects under development and other market conditions to determine whether it would need to use any of the following tools to make up for unanticipated procurement need: (a) procure Category 3 products to make up for small volumes; (b) utilize banked procurement when available; and/or (c) procure additional category 1 or 2 products to make up larger volumes. SDG&E does not believe that the current procurement process moves fast enough to warrant required annual solicitations. The two year procurement authorization cycle is more appropriate as the utilities approach full compliance. A summary of the pros and cons of this approach is set forth below.

Pros	Cons
ffi Provides flexibility to procure only when necessary. For example, as discussed in Section I above, SDG&E expects to be able to achieve RPS goals for CP2 with contracts that it has already executed, and is currently focused primarily on procurement of projects that will provide most of their generation in the third compliance period. Holding an RFO in 2012 to solicit projects that will begin deliveries in 2017 may not be ideal because SDG&E would likely be procuring projects that are at very early stages of development when it is difficult, if not impossible, to assess project viability.	ffi Project failures, spikes in retail sales, transmission failures or other unanticipated market pressures could result in the need to procure additional resources in a year when the utility will not hold an RFO. ffi Could increase instances when bilateral procurement must be benchmarked to outdated solicitation data. Potential Solution: ffi Bilateral projects must contain pricing that is indexed to the price of the applicable generator technology (solar panels, wind turbines, etc). The price would be adjusted at COD based on the market index. This could result in a lower price or a higher price depending on the market at COD. ffi Other potential solutions are discussed in section 6.9 above.

XIX. UTILIZE THE COMMISSION'S RPS PROCUREMENT PROCESS TO MINIMIZE TRANSMISSION COSTS

The Commission has proposed a process to better align the RPS procurement process with the CAISO's transmission planning process. The basic proposal can be summarized in 4 steps:

Step 1: CAISO determines how much capacity is available in each study area

Step 2: IOUS develop shortlists

Step 3: IOUs submit draft shortlist to the Commission

Step 4: If too many projects are shortlisted in a certain study area, CPUC rations out capacity to best ranked projects among all IOUs and confirms results with CAISO

Step 5: Losing bids remain on shortlist but cannot be executed unless another project does not get executed within 12 months.

SDG&E is generally in favor of this proposal and is supportive of this effort to more efficiently allocate available transmission capacity. A summary of the pros and cons of this approach is set forth below, along with specific suggestions to improve this process.

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///
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Summary of Proposal	Pros	Cons	SDG&E position
CAISO establishes available MWs in each study area based on RPS goals, and then subtracts this volume of capacity from signed PPAs. The balance is available for newly shortlisted projects.	ffi This methodology is based on the CAISO's recent efforts to improve its transmission planning process ("TPP") by planning for upgrades necessary to achieve 33% rather than upgrades necessary to build all projects in the interconnection queue. The benefit is that projects will no longer receive study results that require upgrades based on the existence of projects that may never come only.	ffi The CAISO's new process will shift the burden of paying for upgrade costs from developers to ratepayers. SDG&E proposes that other measures should be taken to ensure that this valuable capacity is allocated to the most viable and cost effective projects as developers will no longer bear the upfront risk of upgrade costs.	SDG&E agrees that viable projects should be analyzed as such – without the impact of conceptual projects sitting in the queue that will likely never come to fruition. However, SDG&E acknowledges that the resulting shift in risk from developers to ratepayers should be mitigated by a process that clearly prioritizes the most viable and cost effective projects.
IOUS develop shortlists and submit draft shortlist to the Commission	ffi No changes from previous process.		
If too many projects are shortlisted in a certain study area, CPUC rations out capacity to best ranked projects among all IOUs and confirms results with CAISO	ffi This process prevents IOUs from negotiating contracts with projects that cannot be supported by the upgrades that the CAISO has determined are necessary to achieve 33%.	ffi This process depends on an accurate allocation by the CAISO of the upgrades that will be necessary to achieve 33% ffi It may be difficult to determine which project should be awarded the available capacity. The CPUC should consider more than just price. For example, if SCE and SDG&E both have projects shortlisted in the	SDG&E supports a procedure to determine the most viable and valuable projects, but this proposal does present several issues of concern. The first is an accurate assessment by the CAISO and the application of this data by the CPUC. The CPUC should acknowledge that its rationing procedure may

		same study area and only one can be built, the Commission may chose SCE's project because it has a lower ranking price, but SDG&E may have fewer alternatives for securing its RPS compliance. SCE's project may be cheaper, but SDG&E may have a greater need for its more expensive project. If only one can be built, it should be the less expensive project, but the Commission must acknowledge that this process could create an additional barrier to achieving RPS goals. ffi As proposed, the timeline includes multiple points where approval is required – this could cause uncertainty and impede project development. The following is an estimated timeline following the proposal steps, if accurate, a developer would wait approximately 9 months after RFO issuance to know if their project has been shortlisted: a. CAISO determines deliverability that can be supported by the grid without additional high-cost DNU, and deducts PPA's executed in each study area to determine full capacity deliverability remaining for	impair an IOU's ability to reach its RPS goals. It is also important to consider how the proposed timeline will affect project development. SDG&E currently notifies developers of shortlist selection within approximately 5 months of RFO issuance. It is unclear how significantly this timeframe would be altered by this proposed process, and if significant how renewable development would be affected.

		consideration in annual RPS procurement process: Cluster results generally available at the end of each year, add 1 month to determine deliverability available by study area, assuming CAISO has information readily available (Example: Cluster study complete 12/31/12, Results to CPUC 1/31/13) b. IOUs initiate solicitation, and submit draft shortlist to CPUC: approximately 6 months for RFO and bid analysis (Example: Issue RFO 10/1/12, Submit draft shortlist 3/31/13) c. CPUC rations any projects exceeding threshold in an area: assume 1 month for CPUC analysis and results (Example: Shortlist received 3/31/13, Analysis complete 4/30/13) d. CPUC sends results to CAISO: assume 1 month for verification (Example: Received 4/30/13, Validated 5/31/13) e. CPUC provides results to IOUs, IOUs finalize shortlists and submit to CPUC: assume 1 month to finalize and submit (Example: Results received 5/31/13, Shortlist issued 6/30/13)	

Losing bids remain on shortlist but cannot be executed unless another project does not get executed within 12 months	ffi See comments to 7.4 and 7.5 above.		
Comments on Overall Proposal	ffi Helps to eliminate exorbitantly high and inaccurate upgrade cost estimates that assume that more generation will come on line than what is needed to achieve RPS goals.	ffi Difficult to determine which projects are most deserving of the available capacity.	ffi This proposal will shift risk from developers to ratepayers. To make this an effective program addition, the proposal should be structured to safeguard ratepayer interests. To mitigate ratepayer risk, this process must ensure that developers have sufficient certainty to develop enough projects to create a robust and competitive market for RPS procurement. To this end, the shortlist process should facilitate project development by establishing a clear timeline (with dates) to provide developers with as much certainty as possible. The CPUC must also acknowledge the potential additional barrier the rationing process may create for IOU's in achieving their RPS goals.

Attachment 4
Redline Appendix C

SDG&E's 2012 RPS RFO Evaluation Methodology

Below is the assessment methodology and process to be taken by SDG&E and the Independent Evaluator ("IE") to ensure that the bid selection process is transparent and does not favor any technology or counterparty, and is aligned with SDG&E's compliance requirements. Although SDG&E worked diligently with its IE to develop this methodology, this document may require adjustment before issuing of the RFO in order to account for potential market, regulatory, and/or business context changes.

1. Prep-work prior to launching the RFO, gather data to provide a market benchmark. Analysis to be shared with the IE for input and endorsement.

   a. Compliance Period 1

   - SDG&E team to obtain the SP 15 forward curve for 7x24 2013 deliveries. This curve will be used in the evaluation of short-term bundled deals to derive the implied green attribute price being offered.
   - Continue to gather market quotes for unbundled RECs (quotes from brokers and etc~~.)~~.). This information will be used to assess whether the bids received are generally within the market range and to help identify potential areas of collusion or market manipulation.

   b. Compliance Period 3

   - SDG&E team to update the CPUC approved Market Price Referent (MPR) matrixes, mainly by updating these for natural gas prices, for their use in the evaluation of above market prices, as discussed below.

2. Prior to the closing date (TBD) at Noon, receive all bids:

   a. Upon being uploaded to SDG&E's RFO server, all bids are concurrently emailed to the IE and the SDG&E RFO team.

   b. 60-mins past noon on the closing date, the RFO email will accept bids that, because of heavy traffic by the deadline, could not be uploaded via the website (if the developer shows the print screen of the error message). The IE makes the call at 1:00 pm of "no more bids".

3. Between the closing date at Noon and the next business day after closing date~~-~~, COB, organize bid data:

   a. All bids are assembled into a folder taxonomy designed by the IE.

   b. All bids are saved into the folder taxonomy prepared in Step 3.a. The IE and SDG&E will run a macro to compare folder structures and file sizes to ensure the bid population of the IE is identical to the bid population to be analyzed by the SDG&E RFO team. To the extent the folders do not match, a reconciliation effort begins until folders match.

c. Convert all bundled bids into TOD-adjusted pricing units, categorized by pricing type (e.g: Index, fixed price and etc.). For clarity, this conversion will not be applicable to the price of unbundled REC Bids.

d. The relevant data of all bids is exported into an Access database for analysis.

4. ~~Convert~~Initial Bid Assessment

~~e.~~a. For bundled products, convert post-TOD adjusted Bid prices into the Above Market prices as follows:

- The post TOD-adjusted (or flat) prices of Traditional Structure offers and fixed-price Portfolio Structure offers will be converted into Above Market Costs by subtracting the relevant Market Referent Price (MPR) from each Offer Price. This metric will be in the LCBF calculation and therefore is one of the key drivers of the selection process
- For Portfolio Structure bids with indexed null power prices, the fixed REC price component of each bid will be directly assigned as the Above Market Cost.

b. For unbundled RECs, the REC price will be directly assigned as the Above Market Cost to be compared against the Above Market Cost of all other bids.

~~f.~~c. A snapshot of the key statistics of the bids is produced for presentation to the PRG. These statistics will not include prices; at this stage of the process, bids have not been checked for conformance vis-à-vis the RFO requirements.

~~g.~~d. SDG&E and IE will jointly prepare the relevant data needed for the SDG&E Transmission Planning team to calculate Congestion Costs. This process will group together, on a no-name basis, the relevant data of bids (mainly anticipated generation and energy delivery profile) by interconnection points. The IE will then forward this information to SDG&E's Transmission Planning team.

~~h.~~e. Transmission Planning will run studies to determine hourly congestion costs associated with each of the proposed offer groups and provide results to SDG&E's evaluation team and IE.

~~i.~~f. Determine Transmission Cost Adder: For offers for new projects or projects proposing to increase the size of existing facilities, SDG&E performs an initial analysis of costs for transmission network upgrades or additions using the Transmission Cost Ranking Reports ("TRCR") approved by the CPUC. SDG&E anticipates that some bid respondents will fail to participate in a TRCR. Rather than considering these bids to be non-conforming, SDG&E evaluates the offers in order to determine whether the bid's all-in Price could provide a benefit to ratepayers. SDG&E will use TRCR's to estimate transmission costs for these projects. SDG&E will impute costs for these projects only if the total MWs in the applicable TRCR cluster could accommodate the offer that did not participate in the TRCR study.

~~j.~~g. Determine Deliverability Adder: Projects that have energy-only interconnections, or that cannot interconnect directly with elements of the transmission system located within SDG&E's service territory, may be subject to a deliverability adder based upon the difference between a project's TOD-adjusted MPR with and without capacity valuation to capture costs associated with future resource acquisition needs into SDG&E's overall energy and capacity portfolio.

For the 2011 RPS RFO, SDG&E will use a deliverability calculation based upon the differences between SDG&E's approved "Capacity Adjusted" TOD Factors and the Energy Only TOD Factors used in the past. For each TOD period, SDG&E will calculate two TOD-adjusted MPR values; one calculated with the Capacity Adjusted TOD Factors, and one calculated with the Energy Only TOD Factors. SDG&E will then calculate the difference between the two (Capacity Adjusted value minus Energy Only value), replacing any negative difference by zero. The load-weighted average, in $/MWh, is the value of full deliverability for the given bid.

i. Capacity Adjusted TOD Factors and TOD Periods:

TOD Period	Period Days and Hours	Time of day Factor
Winter On Peak	Nov 1 Jun 30 Weekdays 1 pm to 9 pm PST (HE 14 to HE 21)	1.089
Winter Semi Peak	Nov 1 Jun 30 Weekdays 6 am to 1 pm PST (HE 7 to HE 13) Weekdays 9 pm to 10 pm PST (HE 22)	0.947
Winter Off Peak	Nov 1 Jun 30 All Weekend Hours NERC Holiday Hours and Weekday Hours not already considered On Peak or Semi Peak	0.679
Summer On Peak	Jul 1 Oct 31 Weekdays 11 am to 7 pm PST (HE 12 to HE 19)	2.501
Summer Semi Peak	Jul 1 Oct 31 Weekdays 6 am to 11 am PST (HE 7 to HE 11)	1.342

	Weekdays 7 pm to 10 pm PST (HE 20 to HE 22)	
Summer Off Peak	Jul 1 Oct 31 All Weekend Hours, NERC Holiday Hours and Weekday Hours not already considered On Peak or Semi Peak	0.801

ii. Energy Only TOD Factors and TOD Periods:

TOD Period	Period Days and Hours	Energy Only Time of day Factor
Winter On Peak	Nov 1 Jun 30 Weekdays 1 pm to 9 pm PST (HE 14 to HE 21)	1.192
Winter Semi Peak	Nov 1 Jun 30 Weekdays 6 am to 1 pm PST (HE 7 to HE 13) Weekdays 9 pm to 10 pm PST (HE 22)	1.078
Winter Off Peak	Nov 1 Jun 30 All Weekend Hours NERC Holiday Hours and Weekday Hours not already considered On Peak or Semi Peak	0.774
Summer On Peak	Jul 1 Oct 31 Weekdays 11 am to 7 pm PST (HE 12 to HE 19)	1.531
Summer Semi Peak	Jul 1 Oct 31 Weekdays 6 am to 11 am PST (HE 7 to HE 11) Weekdays 7 pm to 10 pm PST (HE 20 to HE 22)	1.181
Summer Off Peak	Jul 1 Oct 31 All Weekend Hours, NERC Holiday Hours and Weekday	0.900

	Hours not already considered On Peak or Semi Peak	

Projects with full deliverability interconnections are assumed to provide the full benefits of capacity, and thus will not receive a deliverability adder in the LCBF assessment of their bids. Projects that choose energy-only interconnections, or that are located outside of California ISO import points (unless dynamically scheduled), will be treated as having no deliverability benefits and the value of full deliverability will be added to their costs in the LCBF computation.

Due to constraints within the California transmission system, resources located within the California ISO but outside of the SDG&E area may not be able to provide full deliverability benefits to the SDG&E system even with a full deliverability interconnection. In such cases, the value of full deliverability for the project will be multiplied by the ratio of System Resource Adequacy payments to Local Resource Adequacy payments received or made by SDG&E prior to the beginning of the 2011 RPS RFO. The product, which is considered by SDG&E to be the current market view of the proportional value of system versus local deliverability within the California ISO, will be added to the cost in the LCBF computation.

Projects within the CAISO that seek full deliverability interconnections will not receive a deliverability adder if connecting within the SDG&E area, or a system deliverability adder if connecting to the CAISO outside of SDG&E's area but within California. Projects interconnecting with non-ISO California utilities that are located in California will receive a system deliverability adder. All energy-only interconnected projects will receive a deliverability adder. The table below indicates the type of adder that would be applied to various project types. Note that the PPA price that each project receives will reflect the project's ability to provide capacity value during the term of the contract.

	~~LOCAL ATTRIBUTE~~			
INTERCONNECTION TYPE	IN SDG&E AREA	IN CALIFORNIA ISO; OUTSIDE SDG&E AREA	IMPORTS TO CAISO FROM WITHIN CALIFORNIA~~*~~	IMPORTS TO CAISO FROM OUTSIDE CALIFORNIA
~~CAPACITY BENEFIT~~ ~~(~~CAISO "FULL CAPACITY DELIVERABILITY"~~)~~ STATUS	~~No~~ Deliverability Adder = 0	~~System~~40% of Deliverability ~~Adder~~ Value	~~System~~40% of Deliverability ~~Adder~~Value	Up to ~~Full~~40% of Deliverability ~~Adder~~Value
ENERGY-ONLY	~~Full~~100% of Deliverability ~~Adder~~Value	~~Full~~60% of Deliverability ~~Adder~~Value	~~Full~~60% of Deliverability ~~Adder~~Value	~~Full~~60% of Deliverability ~~Adder~~Value

~~4.~~5. Develop DRAFT Short List:

The draft Short-list is a first-pass ranking that lets SDG&E determine which offers are most attractive based on a Preliminary LCBF price, which equals:

- **For bundled products**: the Above Market Costs + TRCR based transmission cost estimates + the Deliverability Adder (if applicable) measured in $/MW;
- ~~**Energy Only**: the Above Market Cost + Deliverability Adder, measured in $/MWh; computed from the MPR~~
- **For ~~TREC~~unbundled RECs**: the unbundled REC price measured in $/MWh

The "Preliminary LCBF" price does not include the congestion adder (all bids are assigned a zero congestion adder at this stage). At this point, bids have not yet been screened to determine whether they comply with RFO requirements. Note that for projects in SB2 categories 2 and 3, SDG&E's procurement will be limited by the statutory requirements and the Rim Rock settlement (if applicable).

a. Run query to group bids based on RPS compliance and SDG&E's identified ~~SDG&E's~~ need as follows:

Compliance Period 1: Deliveriesbetween Jan 1 2013 and December 31 2013

Compliance Period 3: CODbetween 4Q2016 and 1Q2017

Offers with deliveries outside these windows will be considered non-conforming, unless ~~between~~ SDG&E's need ~~in CP2~~assessment has changed materially between the time of issuance of this 2012 RPS Plan and the launching of the 2012 RFO.

b. Determine RPS Compliance Period 1 & 2 ~~Need~~Renewable Net Short ("RNS")

~~SDG&E Compliance Period 1 RPS Need is based on the following formula:~~

~~SDG&E's RPS Requirements – SDG&E's Probability Weighted Deliveries (based on executed contracts) = Minimum Margin of Procurement~~

~~Minimum Margin of Procurement (based on Probability Weighted Deliveries) x 150% = SDG&E's Contingent RPS Need[1]~~

SDG&E's CP1 RNS is calculated as described in Section VI of its 2012 RPS Plan.

[redacted]

In case there is a CP1 need and given it will be 2013 by the time the RFO yields a shortlist, which is late into CP1, SDG&E anticipates that it will place a priority on 2011-2012 unbundled RECs (e.g. no development or production risk) and then on short-term bundled offers from existing facilities (e.g. no development risk~~)~~).

c. Rank all the Compliance Period 1 Bids by preliminary LCBF price until 150% of SDG&E's ~~Compliance Period 1 RPS Provisional Need~~CP1 RNS is fulfilled.

SDG&E will shortlist 150% of its CP1 RNS in order to provide an additional volume of potential projects that will be available if higher ranked projects do not materialize. SDG&E will divide its shortlist into 3 tiers, as discussed in Section 7 below.

There is no need in CP2. SDG&E expects to bank any excess procurement into CP3.

d. Determine SDG&E's Compliance Period 3 ~~RPS Need~~RNS

SDG&E ~~Compliance Period 3 RPS Need~~CP3 RNS is ~~based on the following formula:~~

~~SDG&E's RPS Requirements – SDG&E's Probability Weighted Deliveries (based on executed contracts) – SDG&E's Probability Weighted Bank (from CP2 into CP3) = Minimum Margin~~calculated as described in Section VI of ~~Procurement~~ its 2012 RPS Plan.:

~~(Minimum Margin of Procurement x 150[2]%) / 3= SDG&E's Contingent CP3 RPS Need[3]~~

~~[1] To the extent that SDG&E will not receive expected amount of generation all shortlisted offers will be placed on Provisional Shortlist.~~

e. Rank all the ~~Compliance Period 3~~ CP3 Bids by preliminary LCBF price until one third of 150% of SDG&E's ~~Compliance Period 3 RPS Contingent Need~~CP3 RNS is fulfilled.

-SDG&E will shortlist one third of 150% of its CP3 RNS in order to provide a list of projects that will be available if higher ranked projects do not materialize[4]. SDG&E will divide its shortlist into 3 tiers, as discussed in Section 7 below.

f. Sunrise Powerlink ("SPL ~~back-up.~~") After establishing these preliminary Shortlists, if SDG&E finds itself short of the SPL pledge, which is not the case today, SDG&E will consider SPL-eligible projects and add them to the shortlists to re-fill the pledge.

~~5.~~6. Final Short -Lists:

a. All offers in both preliminary Shortlists (CP 1 and CP 3) are screened for conformance[5]. To the extent offers are not conforming, SDG&E will likely discard (given the high number of anticipated offers) or attempt to make it conforming via discussions with the counterparty provided that the non-conformance is minor.

b. Phase 2/GIA consideration (only for CP 3 offers). SDG&E will conduct sensitivity analyses around whether or not projects that have a CAISO Phase 2 interconnection studies or a signed Generator Interconnection Agreements change their shortlist status if ~~these~~this data, which is typically more precise, is available. If ~~by~~ using the Phase 2 or LGIA data ~~makes a project being shortlisted~~ (as opposed to using the TRCR data~~),~~) would move a project onto the shortlist, SDG&E will do so on the basis that having a Phase 2 or an LGIA is a strong sign of viability. If the opposite were true, SDG&E will apply ~~judgement~~judgment and endorse it with the IE and the PRG.

c. Adding Congestion Charges. SDG&E and the IE will add the relevant Congestion Charges to the Bids once obtained from SDG&E Transmission.

~~[2] The reason this figure is multiplied by 150% is because it is reasonable to expect ~33% of what is shortlisted does not come to fruition (67% success rate assumed which is higher than SDG&E's recent trackrecord).~~

~~[3] To the extent that SDG&E will not receive expected amount of generation all shortlisted offers will be placed on Provisional Shortlist. The reason why it is divided by three is because SDG&E expects launching three yearly RFOs over the next few years to reach RPS compliance in 2020.~~

[4] The Compliance Period 3 need is divided by three because SDG&E expects to launch three yearly RFOs over the next few years to reach RPS compliance in 2020.

[5] Conformance check will start earlier if possible

d. Qualitative Factors: SDG&E may differentiate offers of similar cost[6] by reviewing qualitative factors including: (in no particular order of preference)

- Project Viability[7]
- Local reliability
- Benefits to low income or minority communities
- Resource diversity
- Environmental stewardship
- Rate Impacts
- DBE factor

e. SDG&E and the IE will then develop the preliminary Final Short-Lists that includes congestion costs and Phase 2 study results if applicable. Qualitative factors, including project viability or Diverse Business Enterprise factors, will be used as a tie-breaker.

7. SDG&E's shortlists will be organized in 3 ~~categories or~~ Tiers:

- **Tier 1 "Nominal Need":** the projects that are shortlisted because they fulfill SDG&E's Nominal Need, e.g. prior to applying probability weighting. SDG&E will require exclusivity as a condition for Tier 1 shortlisting.

- **Tier 2 "~~Probability Weighted~~Risk Adjusted Need":** the projects that are shortlisted because they fulfill SDG&E's ~~Probability Weighted~~Risk Adjusted Need. For these, SDG&E will attempt to get exclusivity for a limited period.

- **Tier 3 "Contingency Need":** the projects that are shortlisted because they fulfill SDG&E's Contingency Need~~.~~ (150% of the Risk Adjusted Need). These projects will be shortlisted on a "stand-by" basis and counterparties will be informed of such. Exclusivity will not be required for Tier 3 shortlisting.

~~f.~~a. The preliminary Final Shortlist is prepared and shared with the PRG during next viable meeting in Q1 2013 (meeting dates for 2013 are to be determined at this point)

[6] The term "similar cost" is used to indicate expected indifference by the PRG and CPUC as to the cost of one offer or another. The PRG will have access to SDG&E's evaluation and the quantitative and qualitative components of those offers prior to SDG&E's recommendation filing to the CPUC.

[7] SDG&E considers project viability as a qualitative factor and relies on the Energy Division's Project Viability Calculator and self-scores from the bidders. For projects that SDG&E rejects due to low viability scores, SDG&E rescores the projects to affirm the bidder did not unfairly ~~scored~~score itself too low. For projects that SDG&E shortlists, SDG&E rescores the project to affirm that the bidder did not unfairly score itself too high. Projects below a certain viability threshold will not be considered for the shortlist.

~~g.~~b. SDG&E will consider PRG feedback before notifying bidders of whether they have been selected for the Final Shortlist in Q1-Q2 2013.

RPS ~~NEED~~SHORTLIST CALCULATION

(CP1 through CP3)

The table below is illustrative of the methodology that SDG&E will use to determine its need by CP using the most updated data available at the time of the pre-bidders conference for the ~~2012~~next RFO. Between now and then, there will be material changes to the position and therefore needs will be modified. The key message is that SDG&E: (i) will be seeking offers in CP1 if the portfolio underperforms between now and ~~4Q 2012~~the next solicitation, and (ii) for CP3, it will procure ~~whatever~~any unmet need ~~is there~~, net of CP2 into CP3 banking, ~~pro-rata in~~over the course of 3 ~~goes~~solicitations.

Compliance Period	RPS Target (GWh)	~~Probability Weighted Deliveries (GWh)~~	~~Minimum Margin of Procurement (GWh)~~	~~Need (GWh) 150% of the minimum margin of procurement~~Nominal Need (Tier 1 Shortlist)	Risk Adjusted Need (~~MW~~Tier 2 Shortlist)	~~Type of~~Contingent Need (Tier 3 Shortlist)
1	[redacted] TBD	~~TBD~~	~~TBD~~	TBD	TBD	~~Contingent~~TBD
2	[redacted] TBD	[redacted]	[redacted]	None	None	~~N/A~~None
3	TBD			TBD	TBD	TBD

~~Compliance Period~~	~~RPS Target (GWh)~~	~~Probability Weighted Deliveries (GWh)~~	~~Minimum Margin of Procurement (GWh) minus Probability Weighted Bank (GWh) from CP 2~~	~~Need (GWh) 150% of the minimum margin of procurement divided by 3~~	~~Need (MW)~~	~~Type of Shortlist~~

SB_GT&S_0561914

~~3~~	~~23,202~~	[redacted]	[redacted]	[redacted]	~~TBD~~	~~TBD~~

AFFIDAVIT

I am an employee of the respondent corporation herein, and am authorized to make this verification on its behalf. The matters stated in the foregoing **MOTION OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) TO AMEND 2012 DRAFT RENEWABLE PROCUREMENT PLAN** are true of my own knowledge, except as to matters which are therein stated on information and belief, and as to those matters I believe them to be true.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 15th day of August, 2012, at San Diego, California

/s/ Hillary Hebert
Hillary Hebert
Partnerships and Programs Manager
Origination and Portfolio Design Department