SDG&E's Response to
Key Technical Questions for Parties
in Response to Energy Division Proposed Scenarios
for Use in 2012 LTPP (R.12-03-014)

Questions:
1. Are there any technical errors in the proposed scenarios, scenario tool, or 33% RPS Calculator? For any alleged errors, please be very specific in your comments including the location of the error and the correct value, including the source for the revised value. If appropriate, please provide a revised spreadsheet showing any corrected values. Some example questions to consider in identifying factual errors are:

SDG&E Response: SDG&E continues to comb through the RPS calculator model. If additional issues are uncovered, SDG&E will bring them to the attention of the CPUC Energy Division.

a. Are any resources double counted or inappropriately left out of the analysis?

SDG&E Response: SDG&E did not see any issues with the non-renewable resources in its service area. SDG&E believes there are renewable resources within the San Diego area non-CREZ, the San Diego-North CREZ, the San Diego-South CREZ and Imperial CREZs which meet the criteria for the CPUC's discounted core, but appear to be left out of the analysis. Table 1 shows the renewable generating resources that have both a CPUC-approved Power Purchase Agreement and an executed generator interconnection agreement in the San Diego and Imperial Valley areas.

SDG&E notes that substantial planned renewable resources have signed Generator Interconnection Agreements (GIAs) and appear in the August 2, 2012 *IID* [Imperial Irrigation District] *Generator Interconnection Queue.* See Table 2. SDG&E does not know which of these resources may have signed Purchase Power Agreements with CAISO load serving entities. SDG&E encourages the CPUC Energy Division to consult with IID to determine whether any of these resources should be added to the CPUC's discounted core.

b. Are any numbers cited in the proposed scenarios or spreadsheets inaccurate relative to the intended sources?

SDG&E Response: See above. Also, SDG&E questions whether the proposed CAISO "import" number of 16,469 MW is sustainable for the entire 2013 through 2034 study horizon. The CAISO import capability appears to include Existing Transmission Contract (ETC) capacity for municipal utilities which are not part of the CAISO. Also, WECC has released reports suggesting (i) projections of installed generating capacity outside of California, as compared to (ii) forecast load plus planning reserve margins, will not result in enough surplus generating capacity to fill CAISO import capability.

c. Are there any errors in the renewable generation project data in the 33% RPS Calculator?

SDG&E Response: SDG&E continues its review of the RPS calculator model. SDG&E's initial reaction is a concern with two of the values: 1) Distributed Generation across the IOU Service areas, and 2) the amount of renewable power located in the Imperial CREZs. SDG&E explains its concerns below, and would be happy to work with staff on refining these assumptions.

The calculator seems to provide substantially different amounts of Distributed Generation across the three IOUs' distribution service areas. Comparing the Distributed Generation estimates to current peak loads, the amount of Distributed Generation in the SDG&E distribution service area is 5% of SDG&E's peak load. At the same time it is only 1.8% of the SCE distribution service area peak load and 3.8% of peak load for the PG&E distribution service area.

SDG&E believes that neither overall economics, nor the relative peak load levels and locations of service areas, justify such a variation. Moreover, the amounts for the SDG&E distribution service area are inconsistent with SDG&E's contracts with distributed generation, as shown in Table 1, and with results from programs such as RAM where SDG&E is getting <u>no</u> winning bids within its distribution service area – all of the new distributed generation is coming from the other utilities' distribution service areas.

The forecast amounts of distributed generation additions need to be described at a finer level of geographic detail in order to determine if the projects are concentrated within the load centers of the utilities' distribution service areas such that there are no significant transmission impacts, or outside the load centers such that a significant amount of the energy produced by the distributed generation will be delivered to load via the transmission system.
Many of the distributed generation projects in the SDG&E distribution service area are being located on the eastern edge of SDG&E's distribution service area and will use relatively weak 69 kV transmission lines to reach loads. A significant portion of this power will feed into the new ECO substation on the 500 kV Southwest Powerlink.

Failing to account for the specific locations of distributed generation within each utilities' distribution service area may overstate the amount of new generating capacity that can be counted towards a CAISO load serving entity's system and local Resource Adequacy (RA) requirements.

The High DG scenario is especially puzzling. In the High DG case, the amount of DG in the SDG&E distribution service area actually decreases by 45% compared to the Commercial scenario. In comparison, the amount of distributed generation in the High

DG scenario within the SCE distribution service area increases by 400%; 60% for the PG&E distribution service area. SDG&E requests that the CPUC Energy Division provide an explanation for these odd results.

Imperial CREZs: SDG&E believes the amount of new renewable generating capacity in the Imperial CREZs is lower than what is indicated by proposed new renewable generation that has CPUC-approved Purchase Power Agreements (PPA) and that have executed generator interconnection agreements. (See tables above.) It appears the RPS calculator model is identifying only 860 MW of new renewable generation within the Imperial CREZs because this is the assumed maximum amount of generation that can be accommodated by "Available Capacity on Existing Transmission (No Upgrades)," i.e., new generating resources that have no associated transmission costs.

SDG&E is unclear how the 860 MW number was determined; the Sunrise Powerlink project adds over 2000 MW of thermal transfer capability between Imperial Valley substation and the San Diego area. In addition, the CAISO Board has already approved (i) upgrades of Path 42 between the Imperial Irrigation District balancing authority and the CAISO balancing authority that will add over 1029 MW to the path rating by 2018, (ii) an upgrade of the West of Devers system, and (iii) the 500 kV Colorado River-Devers-Valley #2 transmission line. As approved transmission projects, the RSP calculator model should not attach a transmission cost to this planned transfer capability; i.e., these transmission costs should be considered sunk for purposes of ranking potential renewable resource additions within the Palm Springs CREZ, Riverside East CREZ, Imperial CREZs, the San Diego-South CREZ and, possibly, the Twentynine Palms CREZ.

SDG&E believes the RPS calculator model's treatment of transmission costs associated with out-of-state renewables is insufficiently nuanced. For every renewable energy development region outside of California, the model assumes there is zero megawatts of "Available Capacity on Existing Transmission (No Upgrades)" and zero megawatts of "Available Capacity on Existing Transmission (Minor Upgrades)." It is unclear what analysis was used by the CPUC Energy Division staff to reach these conclusions, however the effect of these conclusions is that every megawatt of potential out-of-state renewable generation is assumed to require the construction of a major transmission upgrade. Further, it appears that the RPS calculator model assumes that these major transmission upgrades involve construction of new transmission that spans the entire distance between the out-of-state renewable generation development region and the state of California. There appears to be no consideration of the possibility that some amount of new out-of-state renewable generation could be contractually wheeled to California on existing transmission.

SDG&E also observes that the capital costs assigned to some of these out-of-state major transmission upgrades is far greater than what actual developers of such transmission projects, and the WECC Transmission Expansion Planning Policy Committee (TEPPC), are currently estimating.

Finally, the "Total Losses" assumed for some these out-of-state major transmission upgrades is far greater than what transmission loss studies would actually indicate.

2. Staff has assumed a resource with no current COD estimate in the Energy Commission's list of siting cases (http://www.energy.ca.gov/sitingcases/ALL_PROJECTS.XLS), but meeting other criteria, would be online by 2017. Is this a reasonable assumption? If not, please provide a year and justification.

SDG&E Response: This does not apply to any plants located in the SDG&E distribution service area.

3. If Staff could not locate a COD for an existing resource, Staff assumes a COD of 1/1/1980. Is this a reasonable assumption? If not, please provide a year and justification from a public source.

SDG&E Response: This does not apply to any plants located in the SDG&E distribution service area.

4. Is it appropriate to group renewable resources such as geothermal or biomass in with conventional generators for purposes of estimating resource retirements?

SDG&E Response: SDG&E has no comment.

5. Is a 19% conversion from nameplate small PV capacity to peak production appropriate? If not, what data source and method publically available should be used for this calculation?

SDG&E Response: SDG&E believes using a 19% annual capacity factor to determine the amount of annual energy from behind the meter PV systems is appropriate, as shown in the calculator. SDG&E does not believe 19% is the right value to convert from nameplate small PV capacity to peak production. SDG&E believes 60% is more reasonable based on the current peak time.

6. Please provide a prioritization of staff's proposed scenarios and portfolios, and briefly (no more than 1 page) explain the rational for this prioritization.

SDG&E Response: SDG&E recommends the following scenario and sensitivities in order:

1. **Scenario 1 - Base Case:**

2. **Sensitivity 1E – High Load Growth**: Given the relatively low growth in the base case (only 0.65%) a higher load case sensitivity should be run to determine the overall robustness of the base case results. However, SDG&E would recommend that a new High Load Growth case be developed, that is different than the one proposed by ED staff. The high case should be constructed using the CEC high load growth and low values for Uncommitted EE, Incremental PV and Incremental Demand side CHP.

3. **Sensitivity [1B and 1C] - Nuclear Shutdown cases**: SDG&E believes that a single nuclear shutdown case should be modeled. SDG&E suggests using the "Early Nuclear Retirement" scenario (Sensitivity 1C).

4. **Scenario 3 – High Distributed Generation Case**: Given the Governor's statements more work is needed to determine the cost effective amount of distributed generation.

SDG&E recommends dropping the following cases:

Sensitivity 1A - Environmental Sensitivity: SDG&E does not see any value in running this case since the discounted core of renewable projects meets almost all of the resources needed to meet a 33% RPS.

Sensitivity 1B - Nuclear Shutdown case: Sensitivity 1B should be dropped.

Sensitivity 1D – Low Load Growth: A low load case would not provide as valuable information as the other scenarios and given limited number of cases that can be done, other scenarios or sensitivities should be pursued.

Scenario 2 – No New DSM: SDG&E believes that additional knowledge about the role DSM can play in the future might provide some value but SDG&E does not believe this case will provide the information needed. This case is also problematic in that it sets a base line that is not a realistic view.

Sensitivity 2A – Replicating Transmission Planning Process (TPP) Assumptions: It's unclear what the Commission would learn that would result in specific actions in this case. It should be noted that there is an 80% probability that actual annual peak load will be less than the 1 in 5 peak load level proposed for this case. SDG&E believes that except for purposes of estimating Local Capacity Requirements where a 1 in 10 peak load level applies, the CPUC should use expected (1 in 2) annual peak loads in its planning. Also, there is no transmission planning analysis that assumes forecast loads for every hour of the year (i.e., annual energy loads) will be at a "1 in 5" level.

Table 1- SDG&E Renewable Contracts

CAISO Generator Interconnection Queue Position Number	Technology	Interconnection Location	Installed Capacity reflected in Signed Purchase Power Agreement with SDG&E that is approved by the CPUC or subject to a Feed In Tariff (includes utility-owned projects) (MW)	Status of Interconnection Agreement
N/A	BioGas	Chula Vista, CA	1.5	Feed In Tariff
N/A	BioGas	Chula Vista, CA	1.5	Feed In Tariff
N/A	BioGas	Chula Vista, CA	1.5	Feed In Tariff
N/A	Solar PV	Descanso, CA	1.5	Feed In Tariff
		subtotal San Diego area Non-CREZ	**6.0**	
337	PV	Borrego Substation 69kV	26	Executed Engineering & Procurement Agreement (E&PA) 09/01/10, Restarted E&PA 07/06/11, Executed Large Generator Interconnection Agreement (LGIA) 9/26/11
W6	Solar PV	Borrego Substation 69kV	5	Executed LGIA
		subtotal San Diego-North CREZ	**31**	
653ED	PV	Boulevard East Substation 69 kV	20	Executed Small Generator Interconnection Agreement (SGIA)
159A	WT	East County (ECO) Substation 230kV	150	Executed LGIA 10/26/11
W7	Solar PV	Boulevard East Substation 69 kV	5	Executed SGIA
		Subtotal San Diego-South CREZ	**175**	
442	PV	Imperial Valley Substation 230kV	125	Executed LGIA 7/8/11, LGIA Amendment 6/13/12
510	PV	Imperial Valley Substation 230kV	130	Executed E&PA 6/15/11, Executed LGIA 10/21/11
561	PV	Imperial Valley Substation 230kV	200	Executed LGIA 3/26/12, Written Notice to Proceed (WNTP) & Security due 3/15/13
590	PV	Imperial Valley Substation 230kV	139	Executed E&PA 1/25/12, LGIA finalized ready for execution , WNTP & Security due 9/1/12
608	PV	Imperial Valley Substation 230kV	140	Draft LGIA 8/6/12, Conf Call 8/10/12, WNTP & Security due 1/1/13
493	WT	Sunrise Powerlink 500 kV	265	Executed E&PA 4/19/11; Executed LGIA 6/13/12
		subtotal Imperial CREZs	**999**	

Table 2 – IID Area Renewables

IID Generator Queue Designation	Facility Type	Interconnection Location	Max MW Output (MW)	Status of Interconnection Agreement
GI-2006-15	Geothermal	Midway Substation	49.9	Generator Interconnection Agreement (GIA) Executed
GI-2008-46	Geothermal	Niland Substation	50	GIA Signed
GI-2008-51	Geothermal	Midway Substation	235	GIA Signed
GI-2009-57	Geothermal	Midway Substation	235	GIA Signed
GI-2009-58	Solar PV	"K" 92 KV Line	49.9	GIA Signed
GI-2009-64	Solar	92 KV "J" Line	49.9	GIA Signed
GI-2009-65	Solar	92 KV "J" Line	49.9	GIA Signed
GI-2010-71	Solar	Midway/Bannister 230KV Li	50	GIA Signed
GI-2010-72	Solar	Midway/Bannister 230KV Li	155	GIA Signed
GI-2010-74	Solar	161KV "M" LINE	100	GIA Signed
GI-2009-70	Solar	Midway-Bannister 230KV Li	50	GIA Signed