BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans.	Rulemaking 10-05-006 (Filed May 6, 2010)

REPLY BRIEF OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) REGARDING TRACK I AND TRACK III ISSUES

AIMEE M. SMITH
101 Ash Street, HQ-12
San Diego, California 92101
Telephone: (619) 699-5042
Facsimile: (619) 699-5027
amsmith@semprautilities.com

Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

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I. INTRODUCTION AND SUMMARY

Pursuant to the August 15, 2011 ruling of Administrative Law Judge ("ALJ") Peter V. Allen and Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission" or "CPUC"), San Diego Gas & Electric Company ("SDG&E") submits this Reply Brief regarding system plan issues addressed in Track I, as well as certain additional issues addressed in Track III of the above-captioned proceeding.

The opening briefs filed in this proceeding reflect the general consensus that the Commission should approve the Track I Settlement Agreement filed with the Commission on August 3, 2011, which resolves all Track I issues except: (1) SDG&E's pending request for a need determination for new resources to meet Local Capacity Requirements ("LCR"); and (2) the possibility of need to procure currently uncontracted existing resources.[1/] With regard to SDG&E's LCR need, certain parties oppose SDG&E's request for an LCR need determination of 415 MW for the SDG&E service area. As is discussed in more detail below, these parties' claims lack merit. SDG&E's showing of LCR need is fully supported by the testimony of SDG&E witness, Robert Anderson.

1/ *See* Motion of PG&E, *et al*. for Expedited Suspension of Track 1 Schedule and for Approval of Settlement Agreement ("Motion"), filed August 3, 2011 in R.10-05-006.

In the *Administrative Law Judge's Ruling Addressing Motion for Reconsideration, Motion Regarding Track I Schedule, and Rules Track III Issues* issued June 13, 2010 ("ALJ Ruling"), the Commission provided direction concerning certain Rules Track III issues to be addressed concurrently with the System Track I schedule. The ALJ Ruling identified five Rules Track III issues and invited parties to make proposals regarding each in testimony to be served concurrently with Track I testimony. The five Rules Track III issues enumerated in the ALJ Ruling are:

1) Procurement of greenhouse gas ("GHG") related products by investor-owned utilities ("IOUs");

2) Procurement rules relating to once-through cooling ("OTC") facilities;

3) Refinements to the bid evaluation process, particularly weighing competing bids between utility-owned generation ("UOG") and power purchase agreements ("PPAs");

4) Refinements to the existing timelines associated with the utilities' request for offers ("RFOs") for resource adequacy ("RA") products; and

5) Procurement oversight rules, including the oversight responsibilities and authority of various entities, including Independent Evaluators ("IEs") and the Procurement Review Group ("PRG"), and standards of conduct ("SOCs") applicable to the IOUs and their employees.[2/]

Parties' opening briefs reflect a variety of views on the first, third and fifth of these Track III issues, which are discussed below. With regard to the second issue, there was general consensus that the Commission should not adopt a proposal presented by Energy Division staff concerning limitations on IOU contracting with OTC facilities.[3/] No party offered a proposal on the fourth issue related to refinements to the existing timelines associated with utility RFOs for

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2/ ALJ Ruling, p. 6.

3/ *See, e.g.,* Opening Briefs of SDG&E, Pacific Gas & Electric Company ("PG&E"), Southern California Edison Company ("SCE"), the Division of Ratepayer Advocates ("DRA"), the Independent Energy Producers Association ("IEP") and the Western Power Trading Forum ("WPTF").

RA product. Accordingly, the record of the instant proceeding does not support a need for such refinements.

II. SYSTEM TRACK I ISSUES

A. The Commission Should Approve SDG&E's Request for an LCR Need Determination of 415 MW

(i) Responsibility for Ensuring System Reliability is Shared by the Commission

As detailed in its opening brief, SDG&E requests that for the period ending 2020, the Commission adopt an LCR need determination of 415 MW for the SDG&E service area. SDG&E's showing of LCR need is based upon updates/corrections to several mandated assumptions related to the need analysis included in the *Assigned Commissioner and Administrative Law Judge's Joint Scoping Memo and Ruling* issued December 3, 2010 ("Scoping Memo").

In D.06-06-064, the Commission established a local RA procurement obligation, noting that "LSEs could be resource-adequate on an aggregate or system basis but transmission-constrained local load pockets could still be resource-deficient."[4] The LCR is the amount of generation capacity that must be owned or under contract within the load pocket in order to meet adopted reliability criteria.[5] The decision requires that LCRs be allocated to individual Commission-jurisdictional load-serving entities ("LSEs") pursuant to a Commission-approved allocation methodology, and provides that such LSEs are subject to penalties for failure to meet local procurement obligations.[6]

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[4] D.06-06-064, *mimeo*, p. 5.
[5] *Id*. at pp. 12-13.
[6] *Id*. at pp. 3, 4, 24, 66-69.

The responsibility to ensure local reliability is shared by the Commission. Indeed, the Commission has acknowledged the central role it plays in ensuring reliable electric service to the state's 11.5 million electric customers, observing that "California's economy depends on the infrastructure the California Public Utilities Commission (CPUC) and utilities provide. For almost 100 years, the CPUC has worked to protect consumers and ensure the provision of safe, reliable utility service and infrastructure at reasonable rates, with a commitment to environmental enhancement and a healthy California economy."[7/]

The importance of providing reliable electric service to customers cannot be overstated. The state's economy, as well as the safety and well-being of its residents, requires access to an adequate and dependable electric supply. While California is a leader in promoting environmental initiatives, its environmental policy goals have always been undertaken in the context of the need to ensure adequate and reliable electric service to California consumers. The Commission has acknowledged the balance that must exist between the various policy goals of the state, observing that "[a]s we seek a cleaner energy future in pursuit of our AB 32 goals, we remain cognizant of our responsibility to ensure the reliability of our system," and further that "[e]ven with energy efficiency, demand response, and renewable resources, investments in conventional power plants and transmission and distribution infrastructure will still be needed."[8/]

The Commission has emphasized that it does not support a "just in time" approach to meeting the LCR procurement obligation; it has made clear that planning for and procuring new resources must occur well in advance of the need for the resources. In D.07-12-052, for example, the Commission noted that "the time required to develop and carry out competitive

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7/ Commission Fact Sheet "The California Public Utilities Commission Regulating Essential Services" located at http://www.cpuc.ca.gov/NR/rdonlyres/9834890A-FA9F-49C1-9043-FA06BDE45E3D/0/AboutCPUC0410_rev2.pdf.

8/ Energy Action Plan, 2008 Update, p. 15.

long-term RFOs, then finance, permit and construct new generation resources – including a cushion to account for unanticipated delays – requires that these procurement decisions be made *up to seven years in advance of when the resources are needed*."[9] In D.09-01-008, it expressly directed SDG&E to take proactive steps to prevent development of a reliability crisis in which there exists insufficient time to engage in additional procurement.[10] Accordingly, SDG&E seeks to comply with the Commission's clear directive to avoid "just in time" resource additions by requesting its LCR need authorizations far enough in advance to allow sufficient time to carry out the Commission's procurement protocols, including the time needed to conduct a second round of procurement, to the extent it is necessary to do so. Likewise, the Commission must do its part to ensure that "just in time" procurement is avoided, and that SDG&E is afforded enough lead-time to finalize contracting activities such that developers will have the time they need to construct and bring new generation resources online.

(ii) SDG&E's 415 MW LCR Need Showing is Based on a 2% Load Growth Rate and Other Corrections to Scoping Memo Assumptions

SDG&E's distribution service area is treated as a single load pocket.[11] To determine its LCR need for purposes of the IOU Common Scenarios,[12] SDG&E developed assumptions and calculated an LCR table (Table 2 included in Mr. Anderson's Track I direct testimony) based upon SDG&E's current outlook regarding resources in its distribution service area and a

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9/ D.07-12-052, *mimeo*, p. 21 (emphasis added).

10/ D.09-01-008, *mimeo*, p. 18.

11/ SDG&E/Anderson, Exh. 310, p. 2.

12/ As a supplement to the CPUC-Required Scenarios mandated by the Scoping Memo, SDG&E, PG&E and SCE developed three alternative scenarios (the "IOU Common Scenarios") and a sensitivity analysis using the same input databases used for the four CPUC-Required Scenarios. Certain variables in the input databases were modified to reflect alternative assumptions that align with the IOUs' expectations. The IOUs submitted joint testimony (the "Joint IOU Testimony") that provides modeling analysis and results of the CPUC-Required Scenarios and the IOU Common Scenarios and sensitivity (the "Joint Analysis"). *Id.* at p. 1.

conservative estimate of 1% load growth[13/] over the planning period.[14/] Mr. Anderson's Track I testimony explains SDG&E's adjustments to the Scoping Memo assumptions.

Table 2 shows that the San Diego LCR area will have a total local area need ("Local Resource Need") of 2440 MW in 2017 and 2713 MW in 2020. It estimates net local capacity – *i.e.*, the local capacity that San Diego area LSEs may rely upon to satisfy their LCR for the San Diego LCR area – of 1867 MW in 2017-2020.[15/] This produces a local capacity shortfall ("need amount") of 573 MW in 2017, growing to 846 MW in 2020. The Table shows how a portion of this capacity need amount might be met each year through "Proposed Resources" – *i.e.*, resources that are uncertain in that they do not exist today, or alternatively, that exist today, but may be eliminated in the future. Even after adding these proposed resources, however, the Table shows a local capacity shortage of 41 MW beginning in 2017, increasing to 180 MW in 180.

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13/ All references to load growth refer to load growth after being reduced for the impacts of energy efficiency and demand-side generation such as rooftop PV and CHP applications.

14/ SDG&E/Anderson, Exh. 310, pp. 6-10; *see also* Joint IOU Testimony, Exh. 106, Ch. 5.

15/ The "Net Local Capacity" value is reduced to reflect the anticipated retirement of the Cabrillo II peaker facilities in 2013. SDG&E/Anderson, Exh. 310, p. 7.

Table 2

Peak Load Calculations (MW):	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forecast Peak-Hour 1-in-2	4438	4536	4615	4696	4772	4851	4930	5014	5099
Forecast Peak-Hour 1-in-10	4882	4990	5077	5166	5249	5336	5423	5516	5609
Transmission Capability (-)	2500	3500	3500	3500	3500	3500	3500	3500	3500
Generation Contingency (+)	604	604	604	604	604	604	604	604	604
Local Resource Need	**2986**	**2094**	**2181**	**2270**	**2353**	**2440**	**2527**	**2620**	**2713**
Existing Local Supply Resources	1894	1894	1894	1894	1894	1894	1894	1894	1894
Existing OTC	1271	1271	1271	1271	1271	1271	1271	1271	1271
Small Hydro	4	4	4	4	4	4	4	4	4
Existing CHP	136	136	136	136	136	136	136	136	136
Local Renewable Energy	21	21	21	21	21	21	21	21	21
Total: Existing Capacity	**3326**	**3326**	**3326**	**3326**	**3326**	**3326**	**3326**	**3326**	**3326**
OTC Retirement	311	311	311	311	311	1271	1271	1271	1271
Other Retirements	0	0	188	188	188	188	188	188	188
Net Local Capacity	**3015**	**3015**	**2827**	**2827**	**2827**	**1867**	**1867**	**1867**	**1867**
Capacity (Need) or Surplus	**29**	**922**	**647**	**557**	**474**	**-573**	**-660**	**-752**	**-846**
Proposed Resources									
Known High Probability Adds	55	55	55	55	55	40	40	40	40
RPS in service area	0	34	68	68	68	68	68	68	68
Additional Supply CHP	0	3	5	8	10	31	34	36	39
Additional Demand-Side CHP	0	2	3	5	7	12	14	16	17
Uncommitted EE	0	34	60	87	126	169	213	251	284
Demand Response	158	196	205	208	210	212	214	217	219
Total Assumed Additions	**213**	**324**	**396**	**430**	**475**	**532**	**582**	**627**	**666**
Capacity (Need) or Surplus	**242**	**1245**	**1042**	**987**	**949**	**-41**	**-78**	**-126**	**-180**

The IOU Common Scenarios include as "Proposed Resources" available to meet local resource need certain renewable and CHP resources that, at this point, appear unlikely to be realized. Specifically, Table 2 assumes that 68 MW of new renewable resources will come online by 2020 as the result of SDG&E's Renewable Auction Mechanism ("RAM"), and that 56 MW of new combined heat & power ("CHP") resources will be available by 2020 (39 MW of supply CHP + 17 MW of demand-side CHP). As Mr. Anderson explained, however, the

Commission's rejection of SDG&E's proposal to largely limits its RAM procurement to local generation,[16/] and the current lack of any proposed CHP projects, casts doubt upon the likelihood that these resources will be available to meet local resource need:

> Table 2 of my direct testimony included 68 MW of local renewable projects by 2020, based on SDG&E's Renewable Auction Mechanism (RAM) Advice Letter filing, which looked to favor local projects under the Commission's RAM program. However, the Commission rejected that proposal in Resolution E-4414 and ordered SDG&E to "remove its local category since this category is not in compliance with the Decision." Likewise the table shows 39 MW of new combined heat and power (CHP) supplies by 2020; however, at this time, there are no know or proposed projects.[17/]

As a practical matter, there is no guarantee that the assumed renewable and CHP added for the IOU Common Scenarios will appear in SDG&E's LCR area by 2020. Thus, with the 1% load growth assumed in Table 2, an additional 124 MW (68 MW + 56 MW) would need to be added (plus a reasonable cushion) to the "Capacity Need" amount estimated in Table 2. Table A illustrates this calculation:

Table A

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Capacity (Need) or Surplus	**242**	**1245**	**1042**	**987**	**949**	**-41**	**-78**	**-126**	**-180**
RPS in service area	0	-34	-68	-68	-68	-68	-68	-68	-68
Additional Supply CHP	0	-3	-5	-8	-10	-31	-34	-36	-39
Additional Demand-Side CHP	0	-2	-3	-5	-7	-12	-14	-16	-17
Capacity (Need) or Surplus	**242**	**1206**	**966**	**906**	**864**	**-152**	**-194**	**-246**	**-304**

This uncertainty regarding the future availability of the RAM and CHP resources assumed in Table 2 highlights, more generally, the difficulty inherent in accurately predicting what resources will be available several years into the future (and reinforces the need for an adequate cushion of capacity to account for resources that are not ultimately not realized).

16/ *See* D.10-12-048, *mimeo*, p. 47 ("Accordingly, we will allow any projects located within PG&E's, SCE's, and SDG&E's service territories to participate in RAM and bid into one or more of the IOUs' RAM auctions.") (emphasis added).

17/ *See* SDG&E/Anderson, Exh. 314, p. 6.

Indeed, it is mainly in the "Proposed Resources" category where disagreements exist between the parties as to the correct assumptions to be used for analytic purposes. As is discussed in more detail below, parties challenge the revisions made by SDG&E to assumptions such as energy efficiency ("EE") and demand response ("DR"). <u>As Mr. Anderson explained, however, the single biggest factor influencing SDG&E's LCR need is what load growth will be after accounting for these assumptions</u>.[18/]

The CPUC-Required Scenarios assume a 0% load growth after EE and demand-side generation is taken into account; the IOU Common Scenarios assume a load growth rate of 1% after EE and demand-side generation is taken into account. Historically, however, SDG&E has experienced a load growth rate, after EE and demand-side generation is taken into account, of approximately **2%** (indeed, SDG&E has observed 5-year load growth rates as high as 5.5%).[19/] <u>If a historical load growth rate of 2% is applied, the need for resources will increase by over 900 MW in 2020 in the Scoping Memo's Trajectory Case[20/] and by approximately 400 MW in the IOU Common Scenarios</u>.[21/] The 2% rate is not an extreme load growth scenario, as Mr. Anderson explained.[22/] Rather it is the actual observed average 10-year load growth for the 10-year periods ending in 2000 through 2010 (*i.e.*, the average of 10 separate 10-year periods).

Thus, even assuming, *arguendo*, that certain debated assumptions are higher that what SDG&E anticipates (EE, for example), applying the historical load growth rate of 2% (rather than 0-1%) will result in an LCR need much great than is contemplated in either the CPUC-Required Scenarios of the IOU Common Scenarios. Thus, as discussed below, the 415 MW

18/ SDG&E/Anderson, Exh. 310, pp. 9-10.
19/ *Id.*
20/ The load and incremental EE assumptions are the same in all of the CPUC-Required Scenarios. Thus, while the discussion herein references the Trajectory Case, the results apply equally in all CPUC-Required Scenarios.
21/ SDG&E/Anderson, Exh. 310, p. 10.
22/ SDG&E/Anderson, Exh. 314, p. 7.

need shown by SDG&E represents a conservative case. Table B below shows the impact of a return to SDG&E's historical 2% load growth. Table B assumes all the same resources are available as are assumed in Table 2 (*i.e.,* it assumes the availability 68 MW of renewable procurement through the RAM program, as well as 56 MW of CHP), but load growth after EE and demand-side generation returns to historical levels. Note that the requested authorization of 415 MW would allow SDG&E to meet local resource need only through 2018.

<u>Table B</u>

	2012	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Capacity (Need) or Surplus	**242**	**1245**	**1042**	**987**	**949**	**-41**	**-78**	**-126**	**-180**
Load growth at 2%	-16	-41	-82	-123	-185	-253	-319	-376	-430
Capacity (Need) or Surplus	**226**	**1204**	**960**	**864**	**764**	**-291**	**-397**	**-502**	**-610**

Thus, SDG&E's request for a 415 MW need determination is fully supported by the testimony of Mr. Anderson. There, he details the impact on SDG&E's LCR determination of assuming that load growth over the LTPP period will be at the 2% average historical level, rather than the artificially low 0% load growth assumed in the CPUC-Required Scenarios or the conservative 1% assumed in the IOU Common Scenarios.[23/] He explains that the 415 MW need determination is based upon a 2% historical load growth assumption and the other adjusted assumptions (*e.g*., EE) included in Table 2 (although, as demonstrated herein, the 415 MW need request is justified even if the Commission relies <u>entirely</u> upon the Scoping Memo assumptions, other than load growth).

It is important to note that the 180 MW of need reflected in Table 2 and the 300 MW of new gas-fired resources assumed for purposes of running the IOU Common Scenarios do <u>not</u> reflect SDG&E's requested LCR need determination in this case. The IOU Common Scenarios were not run for the purpose of determining SDG&E's LCR need. Rather, they were intended to

[23/] SDG&E/Anderson, Exh. 310, pp. 6-10; *see also* Joint IOU Testimony, Exh. 106, Ch. 5.

evaluate need related to renewables integration. Mr. Anderson explained that the 300 MW value "was just what we put into the IOU cases for the purpose of looking at the integration need."[24/] It was not based on a final LCR analysis. Neither the 180 MW value, nor the 300 MW value, take into account the implications of the 2% historical load growth scenario.

(iii) SDG&E's Request for Additional Capacity as a "Cushion" is Prudent Resource Planning

The Division of Ratepayer Advocates ("DRA") and Pacific Environment ("PE") question the need to plan for any margin or "cushion" above SDG&E's calculated need.[25/] DRA points out that the Commission's system need planning reserve margin ("PRM") is currently set at 15-17%.[26/] DRA's apparent assumption that the PRM ensures that a reserve margin exists for local RA is incorrect. Although resources in the San Diego LCR area can and do contribute to the system PRM, the opposite is not true; the system PRM could be met or exceeded on a statewide basis and the San Diego area local RA could still be deficient.[27/] Thus, the existence of the system PRM does not ensure that SDG&E has the extra capacity necessary to respond to unforeseen load growth or other unexpected need in its service territory within the San Diego area.

24/ SDG&E/Anderson, Tr. Vol. 4, p. 250.
25/ DRA Opening Brief, p. 9; Pacific Environment ("PE") Opening Brief, pp. 18-19.
26/ DRA Opening Brief, p. 9.
27/ SDG&E/Anderson, Exh. 314, pp. 6-7.

SDG&E does, however, agree with DRA's observation that "[t]he extra capacity required by the Commission's Resource Adequacy program . . . makes it difficult for sellers to exercise market power."[28] As Mr. Anderson explained during the evidentiary hearing, having extra capacity serves to improve the IOU's negotiating ability and to reduce the RA costs borne by ratepayers:

> Just from my experience, I've been doing resource planning for years. If San Diego has got 2- to 300 megawatts extra, there is some value there. It allows us to get through unexpected load changes. It actually provides some other benefit to ratepayers in that if the amount of capacity is exactly equal to what the ISO says it needs, then every single generator in our load pocket knows they need to get a contract. You basically have no negotiating power with anyone, because everyone knows they get a contract. So if you have some additional capacity in there, it gives us some negotiating ability and actually some cost savings.[29]

Given load and resource uncertainty, SDG&E believes that it is prudent to build a conservative margin into its LCR need showing. As noted above, return to the historical load growth rate of 2% rather than the 0-1% growth the used in the CPUC-Required Scenarios and the IOU Common Scenarios would cause a significant increase in local resource need – it would increase by over 900 MW in 2020 in the CPUC-Required Scenarios and by approximately 400 MW in the IOU Common Scenarios. Given the strong likelihood that the load growth rate during the relevant period in SDG&E's service territory will be closer to its historical average of 2% than to its all-time low of 1.1%, it is reasonable to plan for a modest cushion.[30]

In the context of the IOU Common Scenarios, Table 2 reflects a total San Diego LCR area resource need of 2713 MW in 2020. If, as SDG&E expects, a 2% load growth rate is experienced in the period covered by Table 2, the total local resource need in 2020 would

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[28] DRA Opening Brief, p. 9.
[29] SDG&E/Anderson, Tr. Vol. 4, pp. 251-252.
[30] SDG&E/Anderson, Exh. 310, pp. 9-10.

increase by approximately 400 MW or 14%.[31/] SDG&E proposes a San Diego LCR area need determination of 415 MW, which would provide a 235 MW margin (415 MW-180 MW), or a cushion of approximately 9%.[32/] If the additional resource deletions described above and in Mr. Anderson's Track I rebuttal testimony (*i.e.*, 68 MW of renewable generation through the RAM program and 56 MW of CHP),[33/] are factored in, the cushion is reduced to 111 MW or approximately 4%.[34/] Plainly, given the potential for a 14% increase in local resource need, a 4-9% cushion is reasonable.

Similarly, even if the Commission rejects the analysis in the IOU Common Scenarios and relies on the Scoping Memo assumptions (other than load growth), the cushion requested by SDG&E is still less than the potential increase in local resource need that will occur if SDG&E experiences its historic 2% load growth. Table 1 included in Mr. Anderson's testimony sets forth the Trajectory Case analysis, which relies on the Scoping Memo assumptions and a 0% load growth rate assumption. If instead of the 0% load growth rate assumed in Table 1, SDG&E were to experience a return to its 2% load historical growth rate, the total resource need reflected in Table 1 for 2020 would increase by approximately 900 MW. This would be a 32% increase in projected total local resource need.[35/] SDG&E proposes an LCR need determination of 415 MW, which together with the surplus in 2020 forecasted in Table 1, would provide an 808 MW margin (415 MW + 393 MW), or a cushion of approximately 29%.[36/] Thus, a cushion of 29% is a reasonable request and is, in fact, conservative in that it would not quite cover a load increase of 32%.

31/ 400 MW divided by 2713 MW.
32/ 235 MW divided by 2713 MW.
33/ SDG&E/Anderson, Exh. 314, p. 6.
34/ 111 MW divided by 2713 MW.
35/ 900 MW divided by 2777 MW.
36/ 808 MW divided by 2777 MW.

(iv) Parties' Arguments in Favor of Relying on the Scoping Memo Assumptions are Not Persuasive

As noted above, SDG&E's request for an LCR need determination of 415 MW is based upon a 2% load growth assumption, as well as updates/corrections to multiple assumptions included in the Scoping Memo related to the need determination. Certain parties, most notably the Natural Resources Defense Council ("NRDC"), PE, DRA and Sierra Club California ("SC") urge rejection of SDG&E's corrected assumptions, challenging SDG&E's analysis in the areas identified below. Significantly, however, the opening briefs filed by these parties do not challenge SDG&E's use of the 2% historical load growth rate to develop its LCR need request.

While SDG&E responds herein to the arguments concerning its corrected assumptions set forth in parties' opening briefs, it notes, as discussed above, that it is the load growth rate (after EE and demand-side generation is taken into account) and not EE or any of the other individual assumptions addressed by these parties, that will have the greatest impact on SDG&E's LCR need. Even if the assumptions included in the Scoping Memo are accepted and <u>none</u> of SDG&E's corrected assumptions (other than load growth) are relied upon, the local RA cushion requested by SDG&E is still less than the load increase that would result from realization of a 2% load growth rate. Thus, it is the potential for a return to SDG&E's historic 2% load growth rate after EE that is a primary driver for SDG&E's request for an LCR need determination of 415 MW.

i. <u>Energy Efficiency ("EE")</u>:

It is beyond dispute that the Commission must consider whether a utility's proposed procurement takes into account energy efficiency measures that are <u>reasonably expected</u> to occur. Public Utilities Code § 454.5 makes clear that the IOUs' procurement plans should include only those energy efficiency resources ". . . that are *cost effective, reliable and* *feasible*."[37/] While "stretch" goals serve an important function in encouraging action by utilities and other stakeholders, the Commission's obligation to preserve system reliability cannot be ignored. Likewise, SDG&E must balance its commitment to achieving the energy efficiency goals set by the Commission with its responsibility – not shared by stakeholders such as NRDC and PE – to ensure system reliability.

In its opening brief, NRDC argues that SDG&E's LCR need determination should be based upon the EE assumption included in the Scoping Memo.[38/] It points out that the Scoping Memo EE assumption are based upon the amount that the California Energy Commission ("CEC") determined was incremental to its demand forecast.[39/] NRDC claims that "the amount of efficiency specified in the ACR is conservative because it excludes significant savings that are reasonably expected to come online in the future, or that are already online presently."[40/] NRDC cites, for example, energy efficiency related to California television and appliance standards, as well as measures included in the Big Bold Energy Efficiency Standards ("BBEES"). NRDC asserts that "[m]any of these savings are not only reasonably expected to occur, but are delivering energy savings presently. Thus, actual energy savings will likely be higher than what is specified in the ACR."[41/]

NRDC relies on a flawed premise in making this argument and presents a conclusion that is overly-simplistic. It bases its argument on the observation set forth in the CEC's *Incremental Impacts Report* that "there are additional energy efficiency savings that may be accomplished through time across the entire range of delivery mechanisms that have not been addressed in [the

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37/ Pub. Util. Code § 454.5(b)(9)(C) (emphasis added).
38/ The Natural Resources Defense Council ("NRDC") Opening Brief, pp. 2-5.
39/ *Id.* at p. 3, citing *California Energy Demand 2010-2020 Adopted Forecast*, CEC-200-2009-12-CMF (December 2009) ("CEC Demand Forecast").
40/ NRDC Opening Brief, p. 3.
41/ *Id.* at p. 5; *see also* DRA Opening Brief, p. 7, PE Opening Brief, p. 13, SC Opening Brief, pp. 8-9.

CEC's] analysis."[42/] NRDC fails to acknowledge, however, that the CEC heavily qualifies this observation. The CEC points out in the same discussion (set forth in a section of the Report entitled "Caveats") that "there is no assurance that efficiency savings from any of the three scenarios will be realized. <u>Even the low case requires that various state and federal entities continue to pursue energy efficiency activities under their jurisdiction in what historically is considered an aggressive approach</u>."[43/]

The *Incremental Impacts Report* notes that "the effort to continue increasing efficiency may grow more difficult through time as future initiatives exhaust the low-hanging fruit,'"[44/] and details the uncertainty that exists regarding future committed and uncommitted energy efficiency savings:

> This uncertainty reflects in part the question of whether future policy makers will enact the standards and other programs required to achieve even higher level of cumulative savings. Commissions and boards typically resist making commitments binding on future commissioners and board members, yet the uncommitted program initiatives that are the basis for the 2008 Goals Study presume that the IOU programs will be [sic] continue to be funded at current or higher levels continuously through 2020, that the Energy Commission will continually ratchet building standards tighter with each three-year update cycle and that the Big Bold concepts will actually be enacted on schedule and to an extent comparable to that quantified in the 2008 Goals Study
>
> There are other dimensions of uncertainty that have not been fully explored in this analysis. Decision makers should be aware of the following:
>
> - IOU program impacts constitute a large percentage of total future efficiency savings, and they rely upon voluntary decisions by end users to participate. Unprecedented levels of participation are projected, levels which depend on many factors, including the state of the economy.

42/ *Incremental Impacts of Energy Efficiency Policy Initiatives Relative to the '2009 Integrated Energy Policy Report' Adopted Demand Forecast,* CEC-200-2010-001-CTF (May 2010), p. 54 ("Incremental Impacts Report") located at http://www.energy.ca.gov/2010publications/CEC-200-2010-001/CEC-200-2010-001-CTF.PDF

43/ *Id.* at p. 53 (emphasis added)

44/ *Id*. at p. 54.

- The Energy Commission's 2009 IEPR demand forecast assumes a 15 percent increase in retail prices by 2020, and some impact via price elasticity is included in the base demand forecast. However, it is easily conceivable that retail prices could rise by a significantly different rate, which could result in modifications to presumed utility program activity.

- This analysis and the 2009 IEPR demand forecast rely on a single set of economic/demographic projections. Thus, additional uncertainty in both committed and incremental uncommitted savings estimates is introduced to the extent that the level of economic growth affects customer efficiency adoption decisions.[45/]

NRDC entirely ignores the caveats included in the *Incremental Impacts Report.* It appears to assume that the Report's recognition that additional energy efficiency savings "*may* be accomplished though time" guarantees with certainty that such savings *will* be realized. Plainly, this assumption is faulty. Moreover, NRDC fails to account for the likelihood that, even with greater efficiency realized through programs such as California's television standards, changing conditions may impact other programs in such a way that the greater energy efficiency realized in one area is offset by decreases in efficiency in another area. Mr. Anderson explained this dynamic:

> Q You agree that the California television standards were excluded as well as the updated DOE schedule; is that correct?
>
> A Yes.
>
> Q So wouldn't it be easy to assume that there are these additional savings?
>
> A But you don't know to what extent they would be 100 percent additive to the savings we already have within the case.
>
> Q But you would agree they would be additive?

45/ *Id.*

> A If all else stayed equal, I guess that would be the good case. We know since that incremental report was done, all else does not remain constant.[46/]

Given NRDC's failure to acknowledge the uncertainty inherent in the EE program in terms of efficiency realized through new programs and overall efficiency when all programs are taken into account, the arguments set forth in its opening brief regarding reliance on the Scoping Memo EE assumption should be rejected.

Similarly, NRDC's challenge to SDG&E's EE assumption adjustments lacks merit. As noted above, NRDC's claim that the amount of efficiency contemplated in the *Incremental Impacts Report* is "completely incremental" to the EE forecast is overly simplistic and ignores the dynamic nature of EE.[47/] With regard to NRDC's claim that SDG&E application of a net-to-gross ratio was improper, Mr. Anderson explained that "[f]ailure to do so would result in double-counting of naturally occurring savings that are already embedded in the CEC models, and would not account for the real world effects that evaluation, measurement and verification reports show occur."[48/] Moreover, NRDC's claim that SDG&E applied the net-to-gross ratio to programs based on codes standards and legislation is incorrect;[49/] SDG&E applied the net-to-gross ratio only to the IOU programs. Finally, NRDC's assertion that SDG&E should assume a realization rate of 100% for *all* EE programs through 2020 is unrealistic;[50/] such an assumption would clearly be imprudent in the context of resource planning.[51/] NRDC admits the uncertainty inherent in forecasting future EE, acknowledging that "[i]n 2020, realization rates could be

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46/ SDG&E/Anderson, Tr. Vol. 5, pp. 392-393.
47/ *See* NRDC Opening Brief, p. 6.
48/ SDG&E/Anderson, Exh. 314, p. 4.
49/ *See* NRDC Opening Brief, p. 7.
50/ *See id.*; *see also* PE Opening Brief, pp. 13-14, Sierra Club California ("SC") Opening Brief, p. 8.
51/ PE asserts that "[a] 70% realization rate conflicts with previous SDG&E statements supporting the use of a 100% realization rate." PE Opening Brief, p. 13. Mr. Anderson explained, however, that the example cited during the evidentiary hearing appeared to involve SDG&E's realization rate proposal in the context of a *particular* EE program (as opposed to all EE programs considered in the aggregate). SDG&E/Anderson, Tr. Vol. 4, pp. 222-225.

higher or lower than estimates from 2006 and 2007."[52/] Thus, as the entity responsible for resource planning in its service area, SDG&E *must* take a conservative view of the availability of future resources in its territory.

In considering the arguments raised by NRDC, the Commission must remain mindful of the caveats included in the CEC's *Incremental Impacts Report*. The Report specifically addresses application of the scenarios in the context of resource planning, cautioning that "[w]hile the *Energy Action Plan* loading order emphasizes cost-effective energy efficiency as California's first choice to meet demand growth, <u>relying solely on these resources for long-term resource adequacy is uncharted territory</u>."[53/] It notes further that "[i]f decision makers postpone decisions to invest in supply-side resources and energy efficiency fails to deliver as forecasted, then serious reliability (and cost) consequences could result, unless such shortfalls have been anticipated and contingency actions identified."[54/] Thus, in accordance with the Commission's obligation to "remain cognizant of our responsibility to ensure the reliability of our system,"[55/] NRDC's overly-optimistic assumptions regarding future EE should be rejected and SDG&E's corrected EE assumption relied upon in order to determine its LCR need.

ii. <u>Demand Response ("DR")</u>:

DRA and PE claim that SDG&E's explanation of the DR assumption used in Table 2 is inadequate where it cites DR analysis provided in another case that covers a different time period than in the instant case.[56/]

52/ NRDC Opening Brief, p. 7.
53/ Incremental Impacts Report, *supra*, note 42, p. 55 (emphasis added).
54/ *Id.*
55/ Energy Action Plan, 2008 Update, p. 15.
56/ DRA Opening Brief, pp. 7-8; PE Opening Brief, p. 15.

Mr. Anderson explained that Commission filings made by SDG&E subsequent to development of the Scoping Memo assumptions have forecasted peak reductions significantly lower than those included in the CPUC-Required Scenarios.[57/] He noted further that SDG&E had recently participated in evidentiary hearings held in A.11-03-002, SDG&E's DR application proceeding.[58/] Plainly, it would not be an efficient use of Commission resources to undertake litigation of SDG&E's DR forecast in two separate proceedings. Accordingly, it is logical to incorporate into the instant proceeding the DR numbers included in SDG&E's filings with the Commission, which have been calculated through 2020 based upon current data.

iii. Energy Storage:

DRA and PE also argue that SDG&E should have included contribution from energy storage in Table 2, noting that SDG&E has requested funding of certain energy storage projects in its general rate case ("GRC") filing.[59/] Mr. Anderson noted during the evidentiary hearing, however, that the energy storage projects contemplated by SDG&E are intended "[t]o deal with a specific problem on the system and not to use as supply."[60/] He explained that the proposed energy storage projects are "designed to deal with voltage problems we're having out on our distribution system due to really heavy PV penetrations in certain areas . . . the storage is more to stabilize the distribution system. It's not to be used basically to charge at night and then discharge over peak."[61/] He observed further that "[b]ecause it's designed to help stabilize out the distribution system, and we don't know whether it will need to be charging or discharging at time of peak in that application . . . ***[y]ou can't count on it to be available to meet peak load***."[62/]

57/ Joint IOU Testimony, Exh. 106, Ch. 5, p 8; *see also* SDG&E/Anderson, Tr. Vol. 4, pp. 228-230.
58/ SDG&E/Anderson, Tr. Vol. 4, p. 228.
59/ DRA Opening Brief, p. 8; PE Opening Brief, pp. 14-15.
60/ SDG&E/Anderson, Tr. Vol. 4, p. 235.
61/ *Id*. at pp. 234-235.
62/ *Id*. at p. 236 (emphasis added).

Thus, the claim by DRA and PE that SDG&E improperly excluded battery storage as a RA resource clearly lacks merit and should be rejected.

iv. Renewable Energy Project Additions

DRA and PE assert that SDG&E's need analysis fails to consider potential future renewable energy projects.[63/] PE notes the existence of certain proposed renewable PPAs and various renewable energy programs, and asserts that some or all of the MWs associated with these proposed PPAs and programs should be counted toward SDG&E's local RA. PE first claims that the Commission's RAM program requires that SDG&E procure 81 MW of renewable generation.[64/] While this is an accurate statement of SDG&E's RAM procurement obligation, it does not follow that this generation will be located in the San Diego area load pocket. In implementing the RAM program, SDG&E sought authority to largely limit its solicitation to local generation, but this request was denied by the Commission; the RAM program adopted by the Commission requires that SDG&E accept bids from projects located anywhere in California.[65/] Thus, given the possibility that *none* of the projects procurement through the RAM program will provide local capacity, the 68 MW of net qualified capacity SDG&E originally included in Table 2 as a potential sources to meet the LCR requirement could very likely be zero.

PE next claims that SDG&E improperly excluded contributions from its 100 MW Solar Energy Project ("SEP") approved by the Commission in D.10-09-016.[66/] The SEP consists of two separate components – PPA and UOG. The PPA component requires SDG&E to procure up to 74 MW of solar PV generation through PPAs, with the remaining 26 MW of the SEP program being met through the UOG component. As Mr. Anderson explained during the hearing, the

[63/] DRA Opening Brief, p. 8; PE Opening Brief, pp. 10-12.
[64/] PE Opening Brief, p. 10. SDG&E has requested authority to fold its separate 74 MW Solar Energy Program ("SEP") PPA obligation into its RAM program, which would increase SDG&E's RAM procurement obligation to 155 MW.
[65/] D.10-12-048, *mimeo*, p. 47.
[66/] PE Opening Brief, p. 10; *see also* DRA Opening Brief, p. 8.

PPA portion of the SEP program (74 MW) may be met though purchase of approximately 75 MWs of solar projects secured through two bilateral PPAs.[67/] He noted that "those are connected more into the eastern part of San Diego and will come in over the transmission line. They won't be local."[68/] Thus, the SEP PPAs are not guaranteed resources for meeting the LCR for the San Diego area. Similarly, there is currently no promise of local generation being realized under the UOG portion of the SEP program within the planning period inasmuch as SDG&E has yet to receive a bid that meets the Commission-imposed cost cap for that program, much less begin the lengthy licensing, interconnection study, and construction process.

PE also suggests that SDG&E should have considered in its analysis approximately 40 MW of renewable energy allocated to SDG&E under the Senate Bill ("SB") 32 feed-in-tariff ("FIT") program, as well as two PPAs not yet approved by the Commission and Governor Brown's goal of building 12,000 MW of distributed generation.[69/] SDG&E first notes that SB 32 FIT participants, who are very small generators, do not provide RA benefit to the system since these generators generally do not go through the CAISO process necessary to provide RA credit.[70/] In any event, more generally, it is plainly possible over the planning period that the Commission will approve PPAs or implement new programs that add new local renewable resources; it is equally as likely that any such increases would be offset by decreases in other forecasted local renewable resources, for example if a minimal amount of SDG&E's RAM procurement obligation is met through local projects. PE's apparent belief that all MWs that *might* be available over the planning period can be relied upon for resource planning purposes,

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67/ The Commission has not yet approved these PPAs.

68/ SDG&E/Anderson, Tr. Vol. 4, p. 239.

69/ PE Opening Brief, pp. 10-11.

70/ CAISO Tariff Section 40.4.6.1 requires that before determining an RA resource's Net Qualifying Capacity, the CAISO will ensure that the RA resource "is available to serve the aggregate of Load by means of a deliverability study." In addition to delay and CAISO imposed deposits and study costs, the deliverability assessment may also assign onerous network upgrade costs to individual projects. This combination of cost and delay makes pursuing RA eligibility largely uneconomic for SB 32's 3 MW and under projects.

and that no forecasted resources will fail to materialize, is unrealistic and dangerous from a resource planning perspective. Accordingly, PE's arguments regarding the local renewable resource assumption used by SDG&E should be rejected.

v. Once-Through Cooling ("OTC") Facility Retirements

PE argues that SDG&E overestimates the impact that OTC retirements will have on its local need, alleging that retiring OTC facilities will be replaced with facilities such as the proposed Carlsbad Energy Center.[71/] PE's claim lacks merit. PE relies upon the general discussion included in a 2008 Commission decision rather than evidence entered into the record of this proceeding to support its claim. PE points to no existing, committed resources to support its assertion. The Carlsbad Energy Center, for example, has yet to receive CEC approval of the Application for Certification ("AFC") which is required before any construction activities can begin. The facility is obviously not under construction and, so far as SDG&E knows, no contracts exist to provide the revenue stream that would be needed to move the project forward. Thus, PE's claim is unsupported and should be rejected.

Plainly, given the obligation – shared by the Commission and SDG&E – to ensure system reliability, and the Commission's policy in favor of avoiding "just in time" procurement and of facilitating OTC retirements (which requires that sufficient replacement capacity exists), approval of SDG&E's requested 415 MW LCR need determination is in the public interest. The negative impact of the failure to plan for new resource additions would be significant if SDG&E experiences load growth after EE that is in the neighborhood of what it has experienced on a historic basis. The implications of issuing a need determination that later proves to be higher than necessary are, by contrast, relatively benign. The result would be a modest amount of new, efficient, low GHG-producing, quick-starting resources that can assist with renewable integration

71/ PE Opening Brief, p. 16.

being added in advance of a need date that will only be known in the future. Accordingly, the Commission should approve an LCR need determination of 415 MW for SDG&E's service territory.

III.
RULES TRACK III ISSUES

A. The Commission Should Reject Suggested Modifications to SDG&E's Proposed GHG Product Procurement Plan

In October, 2010, the California Air Resources Board ("CARB") released its *Proposed Regulation to Implement the California Cap-and-Trade Program*[72/] in order to implement Assembly Bill ("AB") 32, in which California established a goal of reducing its GHG emissions to 1990 levels by 2020.[73/] The regulations proposed by CARB would create a GHG emissions allowance cap-and-trade system (the "Cap-and-Trade Program"), with compliance obligations in the electricity sector applicable to "first deliverers of electricity."[74/] The proposed regulations would establish a compliance framework that relies on purchases of "allowances" and "offsets" in order to achieve specified compliance obligations.[75/] The Cap-and-Trade Program compliance obligation was originally scheduled to become effective in January, 2012, but implementation has been delayed. CARB has indicated that it will hold two auctions at some point during 2012, with the first compliance obligation of the Cap-and-Trade Program occurring in 2013.[76/]

As SDG&E witness, Ryan Miller, explained, implementation of the Cap-and-Trade Program will impose costs on SDG&E's bundled customers related to (i) SDG&E-owned generation facilities; (ii) imported electricity purchased under existing long-term contracts and

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72/ The regulation was approved by CARB's Board in December, 2010, but has not yet been finalized or submitted to the Office of Administrative Law for approval.
73/ AB 32, (Stats. 2006, Ch. 488).
74/ "First deliverers of electricity" generally include (i) electricity generators located within California that emit more than 25,000 metric tons of GHGs; and (ii) importers of electricity from outside of California. .
75/ This requirement would not apply to publicly-owned utilities.
76/ *See* http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm.

spot market purchases; and (iii) contractual obligations for GHG compliance responsibility for certain bilateral contracts.[77/] Accordingly, it will be necessary for SDG&E to procure GHG products in order to comply, on behalf of its bundled customers, with Cap-and-Trade Program requirements, and to manage the price risk to bundled customers associated with such compliance. SDG&E's GHG product procurement plan ("GPPP") is set forth in detail in the testimony of Mr. Miller.[78/] The GPPP, when approved, will be incorporated into SDG&E's authorized LTPP[79/] and will constitute the "upfront standards and criteria" envisioned in AB 57 that will guide SDG&E's future procurement of GHG products and determine the eligibility of GHG product procurement costs for rate recovery.[80/]

In their respective opening briefs, DRA, PE and SC challenge certain aspects of SDG&E's GPPP. The arguments raised by these parties are addressed below:

(i) DRA

DRA observes generally that "the upfront standards proposed by SDG&E appear to be reasonable and appropriate."[81/] With respect to risk management/hedging, DRA states that it "does not oppose any of the IOUs' plans regarding financially hedging its GHG price risk."[82/] It suggests that SDG&E's hedging activity be subject to certain limitations outlined in confidential Appendix B to SDG&E's Track III testimony.[83/] SDG&E does not oppose this proposal.

DRA notes that "it does not support forward procurement beyond what is explicitly authorized by the minimum and maximum volume limits presented in SDG&E's confidential

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77/ SDG&E/Miller, Exh. 313, p. 4.
78/ *See id*. at pp. 3-17.
79/ SDG&E's draft LTPP was filed for Commission approval on March 25, 2011.
80/ *See* AB 57, Sec. 2, §§ 454.5(c)(3) and 454.5(d)(2) (Stats. 2002, Ch. 835).
81/ DRA Opening Brief, p. 19.
82/ *Id*. at p. 20.
83/ *Id*. at p. 22.

Appendix B."[84/] DRA's statement mixes two separate concepts. The volume limits presented in SDG&E's testimony apply to each individual "vintage" or annual compliance year (*e.g*., 2013, 2014, etc.); they set parameters on the volumes procured for each compliance period.[85/] SDG&E understands "forward procurement" to refer to how far out in time SDG&E seeks to procure vintages (*e.g*., is procurement limited to the years in the first compliance period, or will SDG&E seek to procure later vintages such as 2017, 2018 and so on?). The minimum and maximum volume limits presented in SDG&E's testimony do not relate to how far out in time SDG&E intends to procure.

As Mr. Miller explained, SDG&E intends, for each compliance period, to comply with the minimum and maximum volume limits presented in its testimony. With regard to the question of forward procurement, SDG&E seeks authority to purchase GHG products as far out in the future as is permitted under ARB's advanced auctions. Thus, under ARB's current structure for advance auctions, at any given time SDG&E may purchase allowances up to three years out. Procurement of allowances outside of the current compliance period will not exceed the minimum volume of allowances SDG&E has forecasted to be required for a given vintage (*e.g.,* 30% of its forecasted emissions for a given year).[86/]

DRA also asserts that the Commission should delay its authorization of IOU procurement of GHG products until CARB's regulations are final.[87/] SDG&E does not support this proposal. Delay in approval of SDG&E's GPPP would serve no useful purpose and, indeed, would disadvantage utility ratepayers. As Mr. Miller explained, while the regulations ultimately

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84/ *Id*. at p. 20.

85/ Earlier vintages may be banked and used in later compliance periods, but vintages in later compliance periods cannot be used to meet obligations in earlier compliance periods.

86/ SDG&E is required to retire 30% of its emissions every year. To the extent SDG&E procures outside of its current compliance period, it will not exceed 30% of its forecast for that year. Once the compliance period rolls over, the forward products purchased by SDG&E would be included in the cumulative volumes used for the minimum and maximum within the compliance period.

87/ DRA Opening Brief, pp. 13-14; *see also* PE Opening Brief, pp. 28-30.

adopted by CARB may impact the *amount* of GHG allowances or offsets SDG&E is required to procure on behalf of its bundled customers, SDG&E does not expect to modify its strategy or methodology for GHG procurement.[88/] Approval within the timeframe requested will ensure that there is sufficient time for SDG&E to set up the systems and procedures necessary to implement its GHG product procurement strategy.

Once the regulation is finalized, SDG&E ratepayers will benefit from SDG&E's ability to take advantage of GHG market opportunities that may arise before the compliance obligation of the Cap-and-Trade Program starts in 2013. As discussed above, CARB has indicated that offsets will become available in 2012 once the program is finalized, and secondary markets have *already* begun trading for GHG products.[89/] Thus, as a practical matter, approval of SDG&E's GPPP should occur in early 2012 in order to ensure that SDG&E is able to participate in the Cap-and-Trade Program as soon as it commences. Accordingly, SDG&E's GPPP should be approved no later than the first quarter of 2012.

Finally, DRA claims that the IOUs' respective GHG product procurement plans should be modified to address allocation of GHG costs and risks in electric PPAs.[90/] SDG&E agrees that it will be necessary to equitably resolve issues related to allocation of GHG cost/risks in PPAs, including the five questions enumerated in DRA's opening brief.[91/] It does not concur, however, with the conclusion that the IOUs' individual GHG product procurement plans offer the appropriate framework for evaluation of how GHG-related cost/risk allocation should be undertaken in the PPA bid evaluation context.

88/ SDG&E/Miller, Exh. 315, p. 5.
89/ *Id*. at p. 1.
90/ DRA Opening Brief, p. 14.
91/ *See id*. at pp. 14-15.

As a practical matter, the question of when and how SDG&E will procure GHG offsets and allowances is separate and distinct from the consideration of its current PPA bid evaluation process and whether changes are necessary to account for GHG-related costs associated with its PPAs. SDG&E's GPPP is intended to establish AB 57 "upfront standards and criteria" that will guide SDG&E's procurement of GHG products – *i.e.*, allowances and offsets – to achieve compliance with the requirements set forth in AB 32. SDG&E's GPPP is not intended to address SDG&E's process for selecting new long-term electric contracts. Rather, SDG&E's GPPP addresses the compliance step *after* SDG&E enters into a PPA with an AB 32 compliance obligation (if SDG&E has responsibility for a compliance obligation) – *i.e.*, it describes how SDG&E will achieve AB 32 compliance through purchase of allowances/offsets (with appropriate mitigation of GHG product price risk). Thus, while, as DRA notes, the LTPP proceeding is generally the correct forum for considering potential modifications to the IOUs' PPA evaluation processes, the issues outlined by DRA should be considered in the context of the bid evaluation process (which is, of course, an integral component of the LTPP proceeding) and not as part of the GHG product procurement element of the LTPP, which does not directly address selection and evaluation of new long-term electric contracts.

(ii) PE

PE claims that the utilities' plans are deficient "because they focus only on obtaining and trading compliance instruments rather than on actually reducing emissions."[92] In addition, it asserts that the IOUs should be required to file advice letters for offset transactions, to comply with additional reporting requirements and to submit their compliance plans to an IE for

[92] PE Opening Brief, p. 20.

review.[93/] Finally, PE proposes that the Commission delay its final decision approving the IOUs' GHG product procurement plans until the end of 2012.[94/]

With regard to PE's claim that SDG&E's GPPP improperly excludes potential GHG mitigation measures, SDG&E notes that the GHG product procurement activities contemplated in the GPPP do not in any way preclude other GHG mitigation efforts by SDG&E. As Mr. Miller noted during the evidentiary hearing, such emission reduction efforts "would come from outside of this plan."[95/] As SDG&E points out above, the GPPP is intended to establish "upfront standards and criteria" consistent with AB 57 to guide SDG&E's procurement of GHG products established as part of CARB's Cap-and-Trade Program. While GHG mitigation will likely be a consideration in evaluation of new projects, contracts, and technologies – indeed, as Mr. Miller observed, "[t]he purpose of the cap-and-trade program is to send price signals to lower emissions[96/] – the GPPP itself is limited to setting forth the upfront standards for GHG product procurement necessary to comply with CARB's regulations. The IOUs' participation in CARB's Cap-and-Trade Program requires that these upfront standards be developed and approved in advance by the Commission.

PE's proposal that the IOUs be required to file advice letters for offset transactions is misguided. As Mr. Miller has explained, imposition of this requirement would likely *harm* ratepayers since the resulting delay would cause SDG&E to miss out on opportunities to purchase cost-effective offsets, which would result in increased costs for SDG&E ratepayers.[97/] Mr. Miller pointed out that "SDG&E expects that ARB cap-and-trade regulations will be designed so that offsets are developed as standard products that can be traded quickly. Requiring

93/ *Id*. at pp. 25-28.
94/ *Id*. at pp. 28-30.
95/ SDG&E/Miller, Tr. Vol. 7, p. 806.
96/ SDG&E/Miller, Tr. Vol. 7, p. 802.
97/ SDG&E/Miller, Exh. 315, p. 2.

the utilities to seek Commission approval for each offset transaction would inject unworkable delay into the process, and would create an unfair competitive advantage for entities not subject to Commission jurisdiction."[98/] Accordingly, the Commission should reject this proposed requirement.

Similarly, the Commission should reject PE's proposal to require the IOUs to submit their respective GHG product procurement plans for IE review.[99/] PE waited until the briefing stage to offer this proposal, thus the record is devoid of evidence establishing any benefit to ratepayers associated with the proposal. The only justification for adoption of this proposal offered by PE is the vague claim that it would "ensure that [the IOUs] are considering the ratepayer and environmental impacts of their compliance decisions."[100/] PE fails, however, to demonstrate that IE review would address a need not currently met through Commission review of the IOUs' GHG product procurement plans. Moreover, PE's proposal to task the IE with conducting an "environmental analysis" far exceeds the scope of IE review approved by the Commission, namely "to ensure a fair, competitive procurement process free of real or perceived conflicts of interest."[101/] Imposition of PE's proposed IE requirement would add unjustified cost and delay into the approval process for IOUs' GHG product procurement plans, which would serve only to harm ratepayers. The record of the instant proceeding clearly does not support adoption of PE's IE review proposal. Accordingly, it should be rejected.

Finally, as explained above, the proposal to delay issuance of a decision approving the IOUs' respective GHG product procurement plans is not in the public interest. PE proposes issuance of an interim decision, with adoption of a final decision delayed until the end of 2012,

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98/ *Id.*
99/ PE Opening Brief, pp. 27-28.
100/ *Id.* at p. 27.
101/ D.07-12-052, *mimeo*, p. 140.

noting that the Commission has elected in the past to adopt energy efficiency goals on an interim basis.[102] Plainly, however, energy efficiency goals are not analogous to procurement authority in a competitive market. SDG&E does not see the benefit of an interim decision with a final decision to be issued at some later point; litigation of the same issues in the context of consecutive decisions on the same topic undermines regulatory certainty and is not an efficient use of Commission resources. As a practical matter, there is no aspect of the Cap-and-Trade Program that will change dramatically between now and the end of 2012, thus there is nothing that would warrant revisiting the grant of authority to acquire allowances and offsets.

(iii) Sierra Club

In its opening brief, SC mounts a collateral attack on CARB's regulations related to the Cap-and-Trade Program. It argues against the use of offsets to comply with AB 32 and suggests that procurement of offsets is subject to the California Environmental Quality Act ("CEQA"). SC's claims are inapposite. As the agency charged with developing GHG emission reduction regulations, it is CARB's responsibility to design, in coordination with the Commission and other stakeholders, California's GHG reduction program.[103] It appears that CARB considered and rejected SC's arguments; it is improper for SC to seek to re-litigate these issues in this forum.[104] The Commission has expressed a general policy disfavoring collateral attacks. Accordingly, SC's collateral attack on CARB's Cap-and-Trade Program should be rejected.[105]

B. The Arguments in Favor of Modification of the Commission's Current Approach to Evaluating Competing UOG and PPA Bids Lack Merit

In the ALJ Ruling, the Commission invited parties to address the potential need for refinements to the Commission's approach to weighing competing bids between UOG and PPAs

[102] PE Opening Brief, p. 29.
[103] AB 32, §§ 38501, 38510, 38560.
[104] *See* SC Opening Brief, pp. 17-18.
[105] *See, e.g.* D.08-04-063, D.07-10-015, D.07-04-017, D.07-03-047.

offered by independent power producers ("IPPs").[106] As a threshold matter, SDG&E notes that PE misstates SDG&E's position on this issue. It states that SDG&E asserts "that the current practice of allowing UOG into the RFO process is effective in maintaining fair competition and need not be changed, as long as it is not from utility build bids."[107] This is not an accurate characterization of SDG&E's position; SDG&E's support for maintaining the current approach to evaluating competing PPA and UOG bids is not subject to the qualification cited by PE.

DRA points out that UOG *can* be compared with IPP PPAs, but recommends certain modifications to the bid evaluation process.[108] Most notably, DRA proposes that in approving UOG projects, the Commission should cap recovery of capital costs and operations & maintenance ("O&M") costs at the level included in the UOG bid.[109] In general, SDG&E does not object to the proposal to cap recovery of capital costs, provided that the IOUs have the right to file an Application to recover additional costs in the event capital costs exceed the amount included in the UOG bid. This approach is fair and is analogous with Commission treatment of IPP requests to re-price PPAs. With regard to O&M costs, however, DRA's proposal is not workable.

Under SDG&E's GRC cost recovery methodology, ratepayer risk is capped on an aggregate basis rather than a project-specific basis. The O&M revenue requirement, for example, is expressed as a *total* amount that covers all O&M costs – an O&M cost on one project that is below what was forecasted may offset a cost overrun on a different project. If *aggregate* costs exceed the O&M revenue requirement, shareholders are at risk for the excess O&M amount. Thus, because the GRC cost recovery methodology does not contemplate

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[106] ALJ Ruling, p. 6.
[107] PE Opening Brief, p. 43.
[108] DRA Opening Brief, p. 33; *see also* The Utility Reform Network ("TURN") Opening Brief, pp. 7-8.
[109] *Id*. at p. 33.

project-specific O&M price caps, the Commission should not adopt DRA's O&M cost cap proposal.

In addition to the modifications proposed by DRA, other parties, such as the Independent Energy Producers Association ("IEP") and the Western Power Trading Forum ("WPTF"), propose modifications to the current approach that would align the evaluation process more closely with their particular interests. IEP, for example, suggest various changes to the current evaluation approach and proposes a complex bid evaluation algorithm, which requires "key elements of several categories of variables [to] be quantified and scored to develop comparisons between projects.[110/] WPTF's proposal is even more extreme; it recommends that UOG be excluded entirely from utility RFOs and that UOG be permitted, if at all, only in the limited circumstance where a competitive solicitation has failed.[111/]

The proposals offered by these parties represent a radical departure from the Commission's current, settled approach to evaluating competing UOG and PPA bids. No party has convincingly demonstrated, however, that the Commission is incapable under the current bid evaluation process of weighing the entire record presented and applying judgment to render a decision as to what resources are in ratepayers' best interests. Nor has any party established that the Commission's handling of the several applications for approval of both UOG and PPAs filed since 2005 was unfair or unreasonable. Absent a credible showing that the current process is unworkable, no justification exists for modifying the Commission's current approach to evaluating PPAs and UOG bids in a hybrid market. Accordingly, the existing evaluation approach should be maintained.

110/ IEP Opening Brief, p. 29.
111/ WPTF Opening Brief, p. 10; *see also* SCE Opening Brief, pp. 21-24.

In the 2004 LTPP decision, the Commission considered and rejected the notion that UOG and PPAs cannot compete head-to-head, concluding that "PPAs and utility-owned resources need to participate in the same all-source open solicitations to ensure [least-cost, best fit ("LCBF")], not in separate PPA and utility-owned specific solicitations . . ."[112/] The Commission was not persuaded by the argument that the IOUs may not conduct an all-source open RFO without a unique UOG/PPA bid evaluation methodology, finding instead that "[t]he IOUs will employ the LCBF methodology when evaluating PPAs and utility-owned bids in an all-source open RFO, taking into account the qualitative and quantitative attributes associated with each bid . . . In addition, when seeking Commission approval for the proposed contracts the IOUs will need to demonstrate that they employed LCBF principles."[113/]

The existing evaluation approach requires that any hybrid product evaluation employ the LCBF guiding principle with oversight from an IE and PRG to ensure that each project's unique circumstances and attributes are captured.[114/] In addition, as Mr. Anderson explained, there are a number of checks on the IOU evaluation process that provide fair evaluation to all bidders. These include:

a. The Commission-adopted SOCs;

b. IE involvement and expertise regarding how to compare UOG and PPA projects; and

c. Full access to the evaluation process by the PRG and Energy Division.[115/]

Thus, the Commission is currently in possession of the tools necessary to analyze the attributes of proposed UOG and PPAs, and to evaluate the differences between the two. Indeed, as noted above, the Commission has considered several applications for approval of both UOG

[112/] D.04-12-048, *mimeo*, p. 139.
[113/] *Id*. at p. 140.
[114/] *Id*. at pp. 217-218, FOF No. 86, 93, 95.
[115/] SDG&E/Anderson, Exh. 313, pp. 19-20.

and PPAs filed since 2005 and has, as Mr. Anderson noted, "demonstrated that it is fully capable of weighing the entire record presented and applying judgment to render a decision as to what resources are in ratepayers' best interests."[116]

Despite the clear lack of any compelling evidence to support the claim that the current process requires modification, IEP proposes several revisions to the existing UOG/PPA bid evaluation approach.[117] IEP proposes, for example, that IOUs be required to provide detailed bid evaluation information to bidders.[118] IEP witness, Mr. Monsen, suggested that adoption of IEP's information disclosure proposal would result in more bids and lower prices, but admitted that past utility solicitations have produced offers that "far exceeded" the capacity needed.[119] As Mr. Anderson pointed out, "if the utilities are receiving bids that exceed the need by up to ten times, increasing the response so that the utilities receive bids that exceed the need by eleven times, or more, will not have much impact on pricing."[120]

In its opening brief, IEP provides a different rationale, attempting to justify its demand for additional bid evaluation information on the grounds that "[e]ven though the Commission requires utilities to adopt a code of conduct . . . the utility staff developing UOG projects and bids may still have better access to relevant information that competing IPPs."[121] IEP provides no evidence, however, of any instance of improper sharing of non-public information between staff involved in developing utility bids and staff who create the bid evaluation criteria and select winning bids. It is clear that IEP's information disclosure proposal is not the result of a

[116] *Id*. at p. 19.
[117] IEP Opening Brief, pp. 17-33.
[118] *See* IEP Opening Brief, pp. 18-19.
[119] *Id*. at p. 10.
[120] SDG&E/Anderson, Exh. 315, pp. 6-7.
[121] *See* IEP Opening Brief, pp. 18-19.

compelling and justifiable need for modification, but rather is designed to create an advantage for IPPs in utility RFOs.

IEP also raises several arguments related to perceived inequities in evaluating UOG and PPA bids. IEP points out, for example, that (i) project development costs may be treated differently in UOG and PPA contexts;[122/] (ii) UOG and PPAs may have different commitment terms;[123/] and (iii) UOG and PPAs may, in some cases, present different types of ratepayer risk.[124] To the extent these differences between UOG and PPA do in fact currently exist, it is clear that they have always existed and that the Commission was well aware of these differences when it adopted the current bid evaluation approach. Plainly, the Commission can, and indeed has on numerous occasions, effectively applied its current policy requiring that any hybrid product evaluation employ the LCBF guiding principle, with IE oversight, to protect ratepayers and promote fair competition.

With regard to IEP's proposed bid evaluation process, SDG&E submits that adoption of IEP's proposed approach would increase the complexity and uncertainty inherent in bid evaluations. Under IEP's approach, several categories of variables would be quantified and scored, with the larger categories being weighted relative to one another and the weighted scores added up to calculate the final score.[125/] The process would require that certain adders (positive or negative) be applied to certain UOG cost elements to reflect the purported ratepayer risk associated with UOG projects.[126/] IEP notes that Mr. Monsen developed estimates of certain

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122/ IEP Opening Brief, pp. 20-22; *see also* WPTF Opening Brief, p. 6.
123/ IEP Opening Brief, pp. 22-24; *see also* WPTF Opening Brief, p. 6; PE Opening Brief, p. 43; DRA Opening Brief, p. 32
124/ IEP Opening Brief, pp. 25-28; *see also* WPTF Opening Brief, p. 6; PE Opening Brief, p. 44.
125/ IEP Opening Brief, p. 29.
126/ *Id*.

adders for illustrative purposes, but that more refined adders could be developed from data that Energy Division obtains from the utilities or other sources."[127]

IEP's proposal is flawed in several respects. First, it would impose significant burden on Energy Division staff, which would be tasked with developing the multiple adders to be used in the bid evaluation. Second, it would inject harmful delay into an already lengthy approval process since it would be necessary to build extra time into the process for the additional complex analysis proposed by IEP. Finally, contrary to IEP's suggestion, it does not appear that its proposal would guarantee greater transparency since at least a portion of the data used to develop the adders would be confidential. In short, IEP's proposal would create a more complicated process with no corresponding value. Since the Commission already has the ability to effectively evaluate competing UOG and PPAs bids, additional "refinements" to the bid evaluation process in the form of a strict, structured set of rules for analyzing UOG and PPAs provide no benefit. The existing bid evaluation approach, which requires that any hybrid product evaluation employ the LCBF guiding principle, with oversight from an IE and PRG to ensure that each project's unique circumstances and attributes are captured, should be maintained.[128]

C. *The Commission Should Not Adopt Proposed Changes to the Procurement Review Group and Independent Evaluator Functions*

(i) <u>Proposed Changes to the Procurement Review Group Process Should Not be Adopted</u>

PE and SC both propose that the Commission require greater public access to procurement review group ("PRG") meetings and materials.[129] The arguments offered by these parties, however, reflect their fundamental misunderstanding of the function of the PRG. PE and SC both appear to assume that the Commission has delegated it approval and oversight authority

[127] *Id*. at pp. 29-30.
[128] *See* D.04-12-048, *mimeo*, pp. 217-218, FOF No. 86, 93, 95.
[129] PE Opening Brief, pp. 50-51; SC Opening Brief, pp. 19-21.

to the PRG. PE conflates the PRG process with the Commission's formal approval process, expressing the concern that "[i]f PRG findings remain confidential, the public cannot know whether the Commission is approving projects that provide them with the most cost-effective energy available."[130/] PE ignores the role of the Commission in enforcing the laws applicable to the IOUs, noting that PRG review is "insufficient to determine whether requirements under Section 454.5 of the Public Utilities Code are being met."[131/] Similarly, SC argues that the PRG is a state body subject to the Bagley-Keene Act.[132/]

These parties' concerns regarding the degree of oversight provided by the PRG and the transparency of the process are plainly misguided. The Commission has made clear that the PRG is intended to act in an advisory role, noting that "PRG recommendations are advisory and non-binding."[133/] Thus, the PRG is not a decisionmaking body with enforcement authority over the IOUs; rather, this function and authority is retained by the Commission, with the PRG serving solely as an advisory body.

With regard to the purported need for greater public access to information presented during PRG meetings, SDG&E witness, Juancho Eekhout, explained the practical difficulties inherent in this proposal, and the extent to which it would undermine the PRG function. He observed that a single topic of discussion at a PRG meeting might have both confidential and non-confidential components.[134/] He pointed out the difficulty of segregating confidential and nonconfidential information related to the same topic, noting that "[o]ften when discussion takes place at the PRG, there is interchange almost immediately between confidential and

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130/ PE Opening Brief, p. 51.
131/ *Id.*
132/ SC Opening Brief, p. 19-21.
133/ D.07-12-052, *mimeo*, p. 119; *see also mimeo*, p. 294, Conclusion of Law 23.
134/ SDG&E/Eekhout, Tr. Vol. 6, pp. 712-713.

nonconfidential information."[135] Mr. Eekhout explained further the difficulty of parsing between confidential and non-confidential information in the context of PRG meetings:

> Q . . . So since you have identified confidential and nonconfidential information, at the PRG meeting you could make a presentation where you presented the nonconfidential information first and then the confidential information afterwards; is that correct, or in the reverse order too?
>
> A It could be hard to do so in practice. It may be impractical because often the case when you get into the topic, the topic has confidential portions and nonconfidential portions. Usually the environment in the PRG is very dynamic, constructive. People go back and forth in a specific topic. They try perspectives.
>
> And it's -- even though, theoretically, like you said, the slides can be distinguished between confidential and non-confidential, in practice what happens is that the debate is so fluid and the discussion is so fluid that it's impractical or almost impossible to distinguish in life what's public versus nonpublic.[136]

Mr. Eekhout elaborated on the dynamic nature of PRG meetings and explained the chilling effect that a PRG disclosure requirement would have on discussion during PRG meetings:

> Q So what is the reason for excluding the public from discussions of nonconfidential information at the PRG meetings?
>
> A . . . [W]hen we distribute the presentation materials, we follow the PUC confidentiality matrix and identify which material is or is not confidential.
>
> However, once it is presented to the PRG, the discussion frequently involves topics and the type of input that isn't necessarily public. I mean, PRG participants have full access to all of our procurement transaction information, and they many times refer to that during any discussions.
>
> So there is not a mechanism to simply discuss only public information separately versus nonpublic information separately, and thus, we have -- and this is clearly laid out in the PUC decisions creating this process. We essentially maintain this as a process where we involve nonmarket participant parties, but it is not a public process.

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[135] *Id*. at p. 712.
[136] *Id*. at pp. 713-714.

> Q A minute ago you testified that you had the ability to distinguish between confidential and nonconfidential information, and you use the confidentiality matrix to do that. Couldn't you make that distinction during a PRG meeting and separate the two and have a public, nonconfidential part of the meeting?
>
> A We do not believe we can. [The] PRG process involves a free flow of ideas and PRG participant's input, and to try to make that distinction on the fly in our opinion is not workable.
>
> PRG participants themselves would need to carefully follow the rules of what is public and what is not public. And, you know, we really believe that the Commission wanted this process to allow nonmarket participant parties to provide a candid, you know, input into our procurement process. And therefore, my answer is no, we do not have an ability to create that separation.[137/]

The Commission has observed that "PRGs are valuable for the IOUs procurement process."[138/] SDG&E concurs with the conclusion that the procurement process benefits from the candid exchange of views that takes place during PRG meetings. The public interest would not be served by transforming the PRG process into a public approval process, or by hampering the ability of PRG members to freely provide their perspectives. Accordingly, the Commission should reject the arguments made by PE and SC regarding a need for greater transparency in the PRG process.

(ii) Changes to the Independent Evaluator Program are not Warranted

In their opening briefs, DRA, PE and The Utility Reform Network ("TURN") propose changes to the current rules governing selection and compensation of IEs in the context of utility procurement. These parties recommend, for example, that IEs be hired by the Commission's Energy Division rather than directly by the IOUs.[139/] DRA further suggests that instead of permitting the IOUs to make IE assignments, the Energy Division or the IOUs' respective PRGs

137/ *Id*. at pp. 548-550.
138/ D.07-12-052, *mimeo*, p. 294, Conclusion of Law 23.
139/ DRA Opening Brief, pp. 27-28; TURN Opening Brief, pp. 8-9; PE Opening Brief, pp. 46-48.

be tasked with making assignment decisions.[140] PE proposes that the scope of the IE program be significantly expanded to include "environmental justice, loading order, need and viability issues."[141]

It is not clear what purpose these proposed changes are designed to serve. PE claims that the modifications it suggests are necessary because "since its inception, IE oversight has been accorded little weight . . ."[142] DRA takes the opposite view, pointing out that "[t]he IE's opinion and report on the IOU's bid evaluation and selection process is a major, if not determinative factor in whether the Commission approves a given project."[143] DRA, TURN and PE each claim that the current practice of having the IOUs hire and manage the IEs might create a conflict of interest;[144] however, these parties fail to cite one example of a circumstance in which a conflict of interest was actually found to exist. Indeed, TURN acknowledges that "the IEs have provided a valuable service to the Commission and ratepayers to date."[145]

The rationale for changing the current IE and selection and compensation process is plainly not compelling to the extent it is based entirely on speculation regarding conduct that, in fact, has not occurred. While the proposed modification would serve no apparent purpose, it would have a detrimental impact on the IOUs' contracting activities by injecting unnecessary bureaucracy and delay into the process. As Mr. Eekhout explained, "[p]arties advocating for this modification do not explain how the proposed approach will ensure continued efficiency and accountability by the IE for the timely and accurate management of workload. Inserting the Commission as middle-man creates a material risk that the IOU will be held up in its

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[140] DRA Opening Brief, p. 28.
[141] PE Opening Brief, pp. 49-50.
[142] *Id*. at p. 46.
[143] DRA Opening Brief, p. 28.
[144] *See id*.; *see also* TURN Opening Brief, p. 8; PE Opening Brief, pp. 46-48.
[145] TURN Opening Brief, p. 9.

procurement activity by an IE that fails to provide timely work product and is not accountable to the IOU for doing so."[146] He further noted that "the proposal is little more than a general idea at this point, with no specifics as to process or potential consequences."[147] The proposal, in short, is ill-conceived and unnecessary, and accordingly should be rejected.

The proposal that the Energy Division have the right to final approval of the use of a particular IE for each RFO is equally misguided.[148] As Mr. Eekhout explained, while the Energy Division's involvement in the IE selection process is beneficial, the IOUs work closely with each of their approved IEs and are in the best position to determine which IEs are most qualified for evaluating certain types of solicitations.[149] He noted, for example, that "certain IEs may have a wealth of experience with renewable procurement, but less experience with Resource Adequacy products."[150] Accordingly, SDG&E proposes that once the PRG and Energy Division select IEs to be part of the potential pool, the IOU should be able to determine which IE has the best skills to participate in each specific solicitation.

Finally, PE's proposal regarding significant expansion of the IE's oversight responsibility is ill-conceived and unjustified. In D.07-12-052, the Commission observed that "[t]he purpose of an IE in the RFO solicitations is to ensure a fair, competitive procurement process free of real or perceived conflicts of interest."[151] Expansion of the IE's current process-oriented role to include the myriad oversight responsibilities proposed by PE would be a major revision to the IE program with significant consequences in terms of the costs borne by ratepayers, among several other considerations. PE provides no analysis, however, of the potential cost of its proposal, the

[146] SDG&E/Eekhout, Exh. 315, pp. 15-16.
[147] *Id.* at p. 16.
[148] *See* ALJ Ruling, Appendix B, p. 11.
[149] SDG&E/Eekhout, Exh. 313, p. 33.
[150] *Id.*
[151] D.07-12-052, *mimeo*, p. 140.

ability (or lack thereof) to locate IEs with all of the necessary competencies or whether more than one IE would be assigned to each transaction. Nor does PE explain why "strong oversight" by the IE is necessary or why Commission oversight of the procurement process is not sufficient to "help ensure protection of ratepayers and the environment.[152] PE fails to establish a need for the type of IE oversight it proposes or to justify the ratepayers cost and process burden that it would entail. Accordingly, PE's proposal to expand the oversight role of the PE should be rejected.

IV.
CONCLUSION

For the reasons set forth above and in SDG&E's opening brief, the Commission should approve the Track I Settlement Agreement submitted on August 3, 2011, and adopt an LCR need determination of 415 MW for the SDG&E service area. In addition, the Commission should resolve the Track III issues enumerated in the ALJ Ruling in a manner consistent with the discussion included in SDG&E's opening brief and herein.

Respectfully submitted this 3rd day of October, 2011.

/s/ Aimee M. Smith

AIMEE M. SMITH
101 Ash Street, HQ-12
San Diego, CA 92101
Phone: (619) 699-5042
Fax: (619) 699-5027
E-mail: amsmith@semprautilities.com

Attorney for:
SAN DIEGO GAS & ELECTRIC COMPANY

[152] *See* PE Opening Brief, p. 49.