**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA**

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| Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans. | Rulemaking 12-03-014<br>(Filed March 22, 2012) |

# OPENING BRIEF OF SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) ON TRACK I ISSUES

AIMEE M. SMITH
ALVIN S. PAK

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

Attorneys for
SAN DIEGO GAS & ELECTRIC COMPANY

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**OPENING BRIEF OF SAN DIEGO GAS & ELECTRIC
COMPANY (U 902 E) ON TRACK I ISSUES**

Pursuant to the ruling of Administrative Law Judge ("ALJ") David Gamson and Rule 13.11 of the Rules of Practice and Procedure of the California Public Utilities Commission (the "Commission"), San Diego Gas & Electric Company ("SDG&E") submits this Opening Brief regarding certain issues addressed in Track I of the above-captioned proceeding.

## I.
## EXECUTIVE SUMMARY

In the *Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judge* issued May 17, 2012 ("Scoping Memo"), the Commission declared that Track I of the instant proceeding would address issues falling into two main categories: (i) local reliability needs in the Los Angeles Basin and Big Creek/Ventura area between 2014 and 2021; and (ii) allocation of responsibility for local reliability procurement obligations and related costs between investor-owned utilities ("IOUs") and non-utility load-serving entities ("LSEs").[1/] The Scoping Memo notes further that "[i]ssues related to infrastructure needs for the San Diego local area are being considered in Application 11-

[1/] Scoping Memo, pp. 5-6.

05-023 and will not be in the scope of this proceeding, except to the extent that any decisions in that proceeding inform the record."[2/]

Because the issue of SDG&E's local reliability need is outside the scope of Track I, SDG&E's discussion herein is focused primarily on the second category of issues described above – *i.e.*, allocation of responsibility for local reliability procurement obligations and related costs between IOUs and non-utility LSEs. SDG&E does, however, address below certain general principles that are relevant to the Commission's analysis of local reliability need, as well the relationship between local reliability in the Los Angeles Basin and Big Creek/Ventura area, and the San Diego and Greater Imperial Valley-San Diego areas.

As requested by ALJ Gamson, SDG&E adheres to the common briefing outline established in the proceeding, but includes only those section headings that are relevant to the issues it discusses herein. Accordingly, the section headings below are not contiguous and, instead, reflect the section numbering of the common brief outline.

## II.
## DETERMINATION OF LOCAL CAPACITY REQUIREMENTS (LCR) NEED IN CALIFORNIA INDEPENDENT SYSTEM OPERATOR (CAISO) STUDIES

### *A. CAISO's LCR and Once-Through Cooling (OTC) Generation Studies*

The studies of the California Independent System Operator ("ISO") provide valuable information and should be relied upon by the Commission for purposes of resource planning.[3/] The Commission should also consider stakeholder comments regarding the ISO's 2012 Annual Transmission Plan, whether aimed at the modeling assumptions used for the 2011-2012 studies or the recommendations the studies

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[2/] *Id* at p. 4, note 4.
[3/] SDG&E/Jontry, SDG&E-1, p. 5.

spawned. In considering such comments, however, the abiding fact the Commission *must* heed is that the ISO is obligated to meet the requirements of the reliability regulations, standards and criteria adopted and enforced by the Federal Energy Regulatory Commission ("FERC"), the North American Electric Reliability Corporation ("NERC") and the Western Electricity Coordinating Council ("WECC").[4/]

The principal purpose of the ISO's 2012 Annual Transmission Plan, upon which the ISO's recommendations in the instant proceeding are based, is to determine whether the ISO system is vulnerable to violations of these federal regulations, standards and criteria. Where vulnerabilities exist, the ISO's studies go on to test the potential means by which those vulnerabilities can be mitigated.[5/] The ISO's 2012 Annual Transmission Plan sets forth the means by which the ISO intends to mitigate all potential reliability-standard violations revealed under the contingency-driven study methodologies required by federal regulations and employed by the ISO. The ISO's recommendations with respect to the need for additional flexible generating resources located in the Western LA Basin subarea represent an important aspect of its plan to address potential reliability issues in its control area.[6/]

Taken in this light, SDG&E submits the ISO's recommendations should be accorded considerable weight by the Commission and, consequently, urges the Commission to approve the method of implementing the ISO's recommendations proposed by Southern California Edison Company ("SCE"). SCE has taken the entirely reasonable position that, in implementing the ISO's recommendations, it will procure "up to" those amounts of flexible capacity located in the Western LA Basin local-reliability

[4/] CAISO/Millar, Tr. Vol. 3, pp. 378, 390-391, 504-505.
[5/] CAISO/Sparks, Tr. Vol. 2, pp. 189-190.
[6/] CAISO/Sparks, CAISO-1, p. 17; *see also* Tr. Vol. 2, p. 192.

subarea recommended by the ISO, leaving the actual amounts of new generation it ultimately procures to be determined by its various procurement activities under an updated and more informed view of the salient circumstances. Once SCE completes its evaluations and procurement activities, the Commission will in due course have the opportunity to review and approve the entire portfolio of SCE-selected resource additions, including resources other than those recommended by the ISO. The Commission should consider disagreements raised in this proceeding regarding the assumptions and derivative results of the California ISO's studies, with the understanding that stakeholders have already had the opportunity to raise their concerns in the ISO's annual transmission planning process, and with the understanding that the ISO has already given concerns raised due consideration.

With respect to the issues raised in the evidentiary record regarding the California ISO's procurement recommendations,[7/] SDG&E reiterates that the ISO's recommendations are principally driven by its interest in meeting the applicable reliability requirements adopted and enforced by FERC, NERC and WECC. Parties appear to be unaware of, or simply ignore, the fact that failure to give due consideration to the ISO's recommendations raises the specter that the *California ISO,* pursuant to its current tariffs and those further authorities the ISO will seek from the FERC in short order, will simply step in to procure resources to the extent the procurement conducted by SCE fails to provide complete assurance these federal reliability standards and

[7/] SDG&E takes no substantive position on the merits of any of the criticisms of the ISO's transmission studies, the assumptions relied upon in those studies, or the specific merits of the study results. SDG&E vigorously participates in the ISO annual planning process and as a matter of record has itself criticized the ISO's study process, assumptions and results. Nevertheless, the ISO study and recommendations at this point should be duly considered for what they are, namely, the ISO's representation to the FERC, NERC and WECC, as well as the ISO's stakeholders, that there is a need for significant new resources in the Western LA Basin in order to resolve potential violations of federal reliability criteria.

regulations will be satisfied. Criticisms that the ISO's studies are erroneous, misguided and/or deficient due to the lack of any explicit "preference" for unconventional and emerging resources should be considered in light of the fact that there are concurrent procurement paths at work in California. In various forums, SDG&E has uniformly taken the position that ISO procurement should be minimized, but if the Commission takes the bait offered by various parties and underestimates the seriousness of the ISO's commitment to protect grid reliability, the ISO can be expected to invoke its procurement authorities to resolve any potential reliability-criteria violations unilaterally and thereafter allocate the costs of its procurements to broad classes of market participants, including those with legitimate claims to being innocent bystanders.[8/]

The ISO's witnesses described the options available to the ISO for resolving any resource shortfalls resulting from the insufficient procurement of resources by the utilities *qua* Participating Transmission Owners. The ISO's options are clearly blunt instruments and second-best procurement tools. They include the execution of reliability agreements, procuring capacity under existing tariffs,[9/] and/or the last resort of suspending the compliance schedules for units subject to the State Water Resources Control Board Resolution 2010-0020.[10/] Importantly, the ISO is also developing new tariffs providing significant additional authorities under which it may procure resources forecasted to be needed in the distant future but that may be at risk of retirement prior to the time of any need, and/or that might serve the ISO's needs for flexible resources and/or local-

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8/ CAISO/Sparks, Tr. Vol. 2, p. 194; CAISO/Millar, Tr. Vol. 3, pp. 449-451.

9/ As the Commission is well aware, while the ISO's tariffs appear to limit the circumstances under which the ISO may procure resources, the ISO possesses the limitless ability to seek a waiver of those limitations by appropriate application to the FERC.

10/ The ISO's role in triggering a suspension of the compliance dates for the units subject to Resolution 2010-0020 are set forth in Attachment 1 to the Resolution, at Section 2.B(2)(a)(b).

reliability resources.[11] SDG&E submits the Commission should fully understand that the decision in this proceeding will affect whether the ISO conducts its own procurements to augment whatever level of resources the Commission authorizes SCE to procure – this should not be taken as a threat made by the ISO, but rather as an important matter of fact borne of the shared responsibilities and jurisdictions between federal authorities and the State.

### *B. Consideration of Preferred Resources, Including Uncommitted Energy Efficiency, Demand Response, Combined Heat and Power, and Distributed Generation, In Determining Future LCR Needs*

The obligation to protect local reliability is shared by the Commission, the ISO and LSEs. 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."[12]

Thus, 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 importance of

[11] CAISO/Millar, Tr. Vol. 3, pp. 451-453. Also, the ISO has submitted substantial information regarding its procurement initiatives to the Commission in Commission Rulemaking.11-10-023, *Order Instituting Rulemaking to Oversee the Resource Adequacy Program, Consider Program Refinements, and Establish Annual Local Procurement Obligations.* Additionally, the ISO's records regarding its proposals and the status of its stakeholder process related to its proposals can be found on the ISO's public website: http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleCapacityProcurement.aspx.

[12] 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.

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. 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."[13/] The Commission's obligation to apply reliability considerations as a check in implementing environmental policy goals is reflected, for example, in the statutory imperative set forth in Public Utilities Code § 454.5 to include in IOU procurement plans *only* those energy efficiency and demand reduction resources ". . . that are *cost effective, reliable and feasible*."[14/]

Ensuring that pursuit of environmental goals does not serve to compromise system reliability requires that a conservative approach be taken to addressing local reliability needs. While reliance on preferred resources such as energy efficiency ("EE") and demand response ("DR") is consistent with environmental policy goals, the need to protect reliability is of paramount importance. Accordingly, only those resources that have a high degree of certainty should be considered for purposes of resource planning. This is of particular importance in the context of local reliability. As SDG&E witness, Robert Anderson explained, "[t]he importance of considering only those local resources that have a high degree of certainty arises primarily from the fact that few fall-back

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[13/] Energy Action Plan, 2008 Update, p. 15.

[14/] Pub. Util. Code § 454.5(b)(9)(C) (emphasis added). All statutory references herein are to the Public Utilities Code unless otherwise noted.

options exist for meeting local need. Thus, the consequences of misjudging the need for new local resources can be severe."[15] In other words, if aggressive assumptions are made concerning the availability of certain resources such as EE and DR, and those resources are ultimately not available at the levels assumed, local reliability could be compromised and, as discussed above, costly ISO backstop procurement would be required.

It is important to note that assuming lower levels of a preferred resource in a load pocket does not signify lack of support for the State's policy initiatives. As Mr. Anderson explained, "a party might support a policy that favors a particular resource type while simultaneously recognizing the uncertainty regarding future availability of that resource type for resource planning purposes."[16] He observed further that "[i]t is important to avoid conflating the resource planning process, which demands pragmatic adherence to realistic forecasts, with the process of establishing 'stretch' goals to encourage particular public policy initiatives."[17]

It should also be noted that protecting local reliability though focusing on local resources with a high degree of certainty in no way de-positions or hinders development of other resources.[18] Although the conservative approach to local resource planning described by Mr. Anderson might result in a value being used for local resource planning purposes that is lower than what might be used for overall system planning, local need is a subset of overall system need. As Mr. Anderson pointed out, "[d]eveloping an IOU's local need on the basis of highly certain resources does not eliminate less certain

[15] SDG&E/Anderson, Exh. SDG&E-1, p. 6.
[16] *Id.*
[17] *Id.*
[18] *Id.*

resources from the overall resource plan; the IOU will still have substantial open positions and can incorporate higher levels of resource(s) in the event they become available."[19/] Thus, taking a conservative approach to determining local reliability needs effectively balances the desire to promote environmental goals with the need to protect local reliability, and is therefore in the public interest.

With regard to the question of which resources, aside from conventional generation, should be considered in determining future local reliability needs, Mr. Anderson explained that "inclusion of certain non-conventional resources may be appropriate, while inclusion of other non-conventional resources is premature at this time."[20/] For example, SDG&E does not challenge inclusion of preferred resources such as EE and DR in the local resource adequacy determination, but notes that only those EE and DR resources that are "cost effective, reliable and feasible" may be considered in determining local reliability needs.[21/] Thus, as Mr. Anderson noted, "the question with EE and DR is less whether it is appropriate to include these resources in determining local resource needs and more how to ensure that only EE and DR savings that are 'cost effective, reliable and feasible' are considered."[22/]

Here, again, the Commission must separate its policy support for these preferred resources from its obligation to base its resource planning determinations on sound, realistic planning assumptions. As Mr. Anderson pointed out, "assigning a 'low' value to a resource such as EE or DR is not an indication of lack of support for that particular resource type, it merely recognizes the inherent uncertainty in the availability of such

19/ *Id.*
20/ SDG&E/Anderson, Exh. SDG&E-1, pp. 6-7.
21/ Pub. Util. Code § 454.5(b)(9)(C).
22/ SDG&E/Anderson, Exh. SDG&E-1, p. 7.

resource and the CAISO's willingness to count such resource for purposes of satisfying LCRs."[23/] He explained further that "[i]n the case of EE, for example, there is a high degree of uncertainty regarding how much uncommitted EE is incremental to the EE that is implicitly included in the load forecast. Uncommitted EE savings are highly uncertain since the assumptions used to develop these estimates depend on untested new technologies, the final adoption of future codes and standards, and strategies that are not fully developed or funded."[24/] Thus, in order to balance environmental goals with the need to protect system reliability, only those EE and DR savings that are ***reasonably expected to occur*** – *i.e.*, the savings that meet the statutory requirement of being "cost effective, reliable and feasible" – can be considered for local resource planning purposes.[25/]

With regard to energy storage and distributed generation ("DG"), Mr. Anderson explained that inclusion of these resources for resource planning purposes is not appropriate at this time. He noted that "[t]here exists no reasonable basis to assume that storage will develop in advance of determining local need in this LTPP cycle," and further that "to the extent energy storage does presently exist, it is intended to deal with intermittency issues. It is not storage that is being specifically designed to contribute to meeting the peak load that local reliability planning must address."[26/]

Similarly, inclusion of DG in the local resource planning analysis presents a challenge at this time. Mr. Anderson pointed out that "[a]lthough many new programs are being proposed for DG, none of the programs require that every DG installation

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23/ *Id.*
24/ *Id.*
25/ *See* Pub. Util. Code § 454.5(b)(9)(C).
26/ SDG&E/Anderson, Exh. SDG&E-1, p. 8.

obtain full deliverability."[27/] He observed that "DG should be considered in determining local reliability needs only where there exists a very high degree of confidence that DG will be present and fully deliverable. In general, this would include only that DG that is currently under construction and will be fully deliverable."[28/] Thus, in order to protect system reliability, *planned* energy storage and DG, as well as existing energy storage and DG that has not been accorded formal deliverability status, should be excluded from the local reliability need determination. However, energy storage/DG should be permitted to compete to meet that need, once it is defined, to the extent those resourced are *actually* available.

The dim view taken by the Commission of "just in time" planning to meet the LCR procurement obligation also highlights the importance of taking a conservative approach to defining the preferred resources available for purposes of meeting local need. The Commission has made clear that planning for and procuring new resources must occur well in advance of the need for the resources.[29/] Thus, a rational balance must exist between support for environmental initiatives, on the one hand, and the need for pragmatic, careful planning in order to ensure adequate and reliable electric service to California ratepayers, on the other. In short, while SDG&E generally supports development of "stretch" goals in the context of proceedings focused on implementation of environmental policy initiatives, it submits that local resource planning demands a practical approach based upon realistic forecasts in order to ensure system reliability is not compromised.

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[27/] *Id.*
[28/] *Id.*
[29/] *See, e.g.*, D.07-12-052, *mimeo*, p. 21.

## III.
## DETERMINATION OF LCR NEED SPECIFIC TO LA BASIN AND BIG CREEK/VENTURA AREA

### *A. LA Basin*

While the question of LCR need specific to the Los Angeles basin is largely outside the purview of SDG&E, consideration of this issue must take into account the relationship between the LCR needs of the Western LA Basin sub-area (and particularly the Ellis sub-area) and the LCR in the San Diego and Greater Imperial Valley-San Diego areas.[30/] As SDG&E witness, John Jontry, explained, SDG&E imports energy into the San Diego and Greater Imperial Valley-San Diego LCR areas via Path 44, a Western Electricity Coordinating Council ("WECC")-recognized path with a post-contingency rating of 2500 MW.[31/] The ability to import energy into these two LCR areas via Path 44 is affected by the amount and location of dependable generation in the Los Angeles basin; in other words, if the LCR need established in the Western LA basin is so low that it results in less than the full 2500 MWs flowing on Path 44 under critical contingency conditions, it will be necessary to acquire more local resources on the San Diego side of Path 44.[32/]

Given the potential for the San Diego and Greater Imperial Valley-San Diego LCRs to be affected by the LCR determinations for the Western LA Basin sub-area and the Ellis sub-area, consideration of the LCR need specific to the LA Basin should include analysis of the resources that are available in the San Diego area and the LA Basin. This approach will enable determination of the overall least-cost and best-fit approach that

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[30/] SDG&E/Jontry, Exh. SDG&E-1, p. 1.
[31/] *See id.* Path 44 is comprised of "the five lines south of San Onofre between San Onofre and San Luis Rey Substation and San Luis Rey and San Onofre and Talega Substations." SDG&E/Jontry, Tr. Vol. 7, p. 1228.
[32/] SDG&E/Jontry, Exh. SDG&E-1, pp. 1-2; Tr. Vol. 7, p. 1229.

ensures that the full 2500 megawatts flows on Path 44 during critical contingency conditions, while minimizing overall cost of LCR resources in the areas in question.[33/] As Mr. Jontry explained, "with respect to local capacity requirements, the LTPP process should honor existing path ratings, including Path 44, and should seek to minimize the combined LCRs for the San Diego and Los Angeles basin areas."[34/] He noted further, "[t]his approach will help to minimize costs incurred by consumers in both the San Diego and Los Angeles areas to ensure that there is sufficient dependable generation available to mitigate reliability standard violations that may arise under the ["ISO's] LCR study methodology."[35/]

## VI.
## COST ALLOCATION MECHANISM (CAM)

### *A. Proposed Allocation of Costs of Needed LCR Resources*

Under the cost allocation mechanism ("CAM") that exists pursuant to § 365.1(c), each IOU must procure the new generation resources necessary to serve its distribution service territory, with the cost and benefits of the capacity associated with these new resources being shared by all "benefitting parties" located in that IOU's service territory. As the Commission made clear in D.11-05-005, application of the CAM is mandatory where the statutory conditions are met.[36/] Specifically, if the Commission makes a determination that the generation resources in question "are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's

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[33/] SDG&E/Jontry, Tr. Vol. 7, pp. 1229-1230.
[34/] SDG&E/Jontry, Exh. SDG&E-1, p. 2.
[35/] *Id.* SDG&E notes that the ISO's once-through cooling ("OTC") studies completed to date have all assumed that the San Onofre Nuclear Generation Station ("SONGS") units are in service. SDG&E suggests that a SONGS-out sensitivity could be performed to inform the Commission as to the robustness of the LCR need findings over time.
[36/] D.11-05-005, *mimeo*, p. 6.

distribution service territory," the costs of procuring such resources *must* be allocated through the CAM.[37]

SDG&E supports continued allocation of capacity costs to all benefitting customers in an IOU's distribution service territory via the existing CAM framework. As the Commission has previously observed, the CAM is necessary to ensure that "the IOUs' bundled customers are not alone responsible for the cost of new generation to retain system reliability."[38] While SDG&E supports continued application of the CAM, it notes the existence a need, discussed below, for further refinements to the CAM.

***B. Should CAM Be Modified At This Time?***

While the Commission has addressed the basic framework and operation of the CAM, it left several important issues open in its most recent CAM decision, D.11-05-005. These include:

1. The development of policies and processes for distinguishing between system and bundled resource needs, and related cost allocation;
2. Whether there should be a test of "who benefits" under Senate Bill ("SB") SB 695, and if so, the construction of such a test;
3. The further refinement of the energy auction process;
4. The development of policies and processes to compare and evaluate PPA versus utility-owned generation bids in a competitive solicitation; and
5. The development of policies and processes for applying the CAM to utility-owned generation.[39]

The record of the instant proceeding is not adequate to allow the Commission to resolve all five of these issues. The Commission can, however, address on the basis of

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[37] *Id.* at pp. 6-7.
[38] D.06-07-029, *mimeo*, p. 59, Conclusion of Law 2.
[39] D.11-05-005, *mimeo*, pp. 16-17.

the existing record the question of "who benefits" under SB 695 (Issue #2), as well as the need for further refinement of the energy auction process (Issue #3).

### (i) The Commission Should Adopt the CAM Modifications Proposed by SDG&E

#### *(a) Rebuttable Presumption regarding "Benefitting Customers"*

SDG&E proposes that the Commission adopt an explicit rebuttable presumption that the net capacity costs of resources it authorizes the utilities to procure (or orders them to build) in order to meet system or local reliability requirements will be allocated to all consumers within the procuring (or building) utility's service territory and recovered via the CAM.[40/] At the very least, this rebuttable presumption should apply to the costs of new generation resources resolving system or local resource deficiencies as may be determined by the Commission.[41/]

As noted above, § 365.1(c), requires that to the extent IOU procurement of new generation resources benefits all customers in an IOU's distribution service territory, the net capacity costs of such procurement must be allocated to all such "benefitting parties" located in that IOU's service territory. As a practical matter, when the Commission defines an IOU's procurement "need" to encompass a need beyond the narrow LCR need of the IOU's bundled customers (*e.g.*, flexibility attribute for renewable integration) and authorizes IOU procurement to meet that broader need, *all* customers in an IOU's distribution service territory benefit from the IOU's procurement. As Mr. Anderson explained, "the Commission may structure its procurement orders to address policies and requirements beyond a utility's loads and, where the reflection of those policies and requirements in a utility's procurement plans redound to the benefit of consumers other

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40/ SDG&E/Anderson, SDG&E-1, p. 11, SDG&E-2, p. 5.
41/ SDG&E/Anderson, SDG&E-2, p. 5.

than the utility's bundled customers, the Commission should allocate costs to all benefitting consumers via the CAM."[42]

Mr. Anderson observed that in authorizing utility procurement, the Commission considers "resource solutions that would address the full extent of resource 'needs' not only as defined by the ISO's analyses, but by a host of other state policies and interest – certainly the Commission can be expected to look beyond the forecasted consumption of utility bundled loads in determining the total needs and the resources that should be used to resolve those needs."[43] He pointed out that "[i]n practice, the Commission has often cooperated with the California ISO to analyze and determine system and local reliability needs within the ISO's footprint. In other cases such as the combined heat and power ("CHP") settlement, the Commission looked to achieve a state-wide policy objective."[44] He noted that "[b]ecause defining needs in this all-encompassing way results in the provision of benefits to customers other than the utility bundled customers, the Commission should allocate the costs of the utility's procurement via the CAM."[45]

Plainly, the conclusion that all LSEs in the reliability area benefit from an IOU's procurement of local resources is reasonable; indeed, this assumption forms the basis for the ISO's approach to allocation of generation resources. Specifically, in circumstances where the ISO acts to procure resources that it determines are needed to meet system or local resource adequacy or reliability requirements, it allocates costs to all LSEs on a load-ratio share basis and deviates from this approach only where the need is attributable

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[42] *Id*. at p. 1.
[43] *Id*. at p. 2.
[44] *Id*. at p. 4.
[45] *Id* at p. 2.

to a specific failure of a single LSE to meet its resource adequacy requirements.[46] Thus, as Mr. Anderson pointed out, "[w]ithout addressing the merits of the ISO's authorities or the manner in which the ISO may choose to exercise them, the cost-allocation principles used in these cases are consistent with the rebuttable presumption I describe in this testimony: by procuring those incremental resources it believes are necessary to meet its operational requirements, the ISO justifiably presumes that *all* loads benefit from the procurement of those resources and accordingly allocates the costs of these procurements on a load-ratio share basis."[47]

Hence, it is reasonable to presume that all customers in an IOU's service territory will benefit from an IOU's procurement of generation resources. Where the occasional situation arises involving generation resources that demonstrably provide benefits only to bundled customers, the presumption would be rebutted. More often than not, however, the opposite will be true and IOU procurement will serve to benefit all customers in its service territory. Adoption of the rebuttable presumption proposed by SDG&E recognizes this fact and will serve to prevent the delay and administrative burden inherent in litigating the issue of "who benefits" in each future individual case in which application of the CAM is proposed. Accordingly, the Commission should establish a rebuttable presumption that the resources that it authorizes the IOUs to procure to meet local reliability need requirements satisfy the statutory conditions of § 365.1(c) and that the CAM applies to such procurement.

[46] SDG&E/Anderson, SDG&E-2, pp. 5-6.
[47] *Id*. at p. 6 (emphasis in original).

*(b) Non-Auction Cost Allocation Mechanism*

SDG&E proposes that the Commission apply a methodology other than the auction method to determine the net capacity costs to be allocated through the CAM.[48/] Under § 365.1(c)(2)(C), the "net capacity cost" to be allocated through the CAM is determined by subtracting the energy and ancillary services value of the resource from the total costs paid by the IOU pursuant to a third-party contract or, in the case of utility-owned generation ("UOG"), the annual revenue requirement for the UOG resource. The provision emphasizes that "[a]n energy auction *shall not be required as a condition for applying this allocation*, but may be allowed as a means to establish the energy and ancillary services value of the resource for purposes of determining the net costs of capacity to be recovered from customers pursuant to this paragraph . . ."[49/] The Commission acknowledged in D.11-05-005 the shortcomings of energy auctions as a means of determining net capacity costs, noting that "the existing energy auction mechanism adopted in D.07-09-044 may need to be revised."[50/]

As Mr. Anderson explained, SDG&E has serious concerns regarding the administrative burden and delay inherent in energy auctions. He pointed out that energy auctions do not ensure that net capacity costs are minimized, and that "an alternative and better methodology would be one that relies on public data to calculate how the relevant resource would have operated had it been made available to the CAISO markets at cost."[51/] He noted further that "[t]his data could be used to estimate market revenues and

48/ SDG&E/Anderson, SDG&E-1, p. 9.
49/ Pub. Util. Code § 365.1(c)(2)(C) (emphasis added).
50/ D.11-05-005, *mimeo*, p. 14.
51/ SDG&E/Anderson, SDG&E-1, p. 10.

thus profits that could be flowed back, thereby reducing the capacity costs for all parties."[52]

In testimony submitted on behalf of the Alliance for Retail Energy Markets ("AReM"), Direct Access Customer Coalition ("DACC"), and Marin Energy Authority ("MEA"), witness Fulmer points out that in applying the CAM to IOU procurement, the Commission has relied in the past on a proxy calculation similar to the non-auction cost calculation mechanism adopted in D.07-09-044.[53] That non-auction cost calculation mechanism (referred to as the "Joint Parties Proposal") was established as part of Joint Settlement Agreement adopted in D.07-09-044, which outlines the principles to be applied in energy auctions used to determine net capacity costs. Under D.07-09-044, the Joint Parties Proposal is an alternative to energy auctions that is available where an auction is unsuccessful or has not yet occurred.[54] Mr. Fulmer points out that "[a]t present, the predominant approach for setting net capacity price seems to be 'non-auction processes.'"[55]

In light of the fact that the Joint Parties Proposal currently exists as a model for non-auction cost allocation and that, as Mr. Fulmer notes, the Commission has previously used this type of non-auction mechanism to allocate costs through the CAM, SDG&E proposes that the Joint Parties' Proposal be deemed to be a fully-available alternative to the use of an energy auction to determine the net capacity costs for resources subject to CAM. SDG&E recommends that the Commission either (i) eliminate the restriction that the Joint Parties' Proposal may be used only if an auction is unsuccessful or has not yet

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[52] *Id.*
[53] AReM/DACC/MEA/Fulmer, AReM-1, p. 36.
[54] *See* D.07-09-044, *mimeo*, p. 1, Appendix A, § IV.
[55] AReM/DACC/MEA/Fulmer, AReM-1, p. 13.

occurred, and permit the IOUs to apply the Joint Parties' Proposal in lieu of energy auctions until it determines through workshops what non-auction method(s) may be used on a permanent basis to establish net capacity costs; or (ii) forego workshops and simply deem the Joint Parties' Proposal to be a permanently available alternative to the energy auction approach to determining net capacity costs.[56] At the time the utility files its application, it would state its preference for which method would be employed. Removing the restriction on use of the Joint Parties' Proposal and establishing it as a fully-available non-auction mechanism for determining net capacity costs would serve the public interest inasmuch as it would provide an immediate means of addressing the Commission's concerns regarding the existing energy auction mechanism adopted in D.07-09-044.[57]

**(ii) The Commission Should Reject the CAM Modifications Proposed by AReM/DACC/MEA**

In her testimony submitted on behalf of AReM/DACC/MEA, witness Mara proposes a two-step process for allocating cost through the CAM. The first step would involve the Commission determining the megawatts of unmet need that cannot be attributed to any specific LSE, and then issuing a decision identifying the megawatt amount of unmet need potentially subject to CAM procurement and the time-frame in which the need occurs.[58] The second step would involve IOU submittal of a CAM application and Commission review based on various criteria proposed by Ms. Mara.[59] In addition, witness Fulmer proposes modifications to the process used to determine the net capacity costs to be allocated through the CAM, as well as adoption of a cap on CAM

[56] SDG&E/Anderson, SDG&E-2, pp. 9-10.
[57] *See* D.11-05-005, *mimeo*, p. 14.
[58] AReM/DACC/MEA/Mara, AReM-1, pp. 32-33.
[59] *Id.* at p. 33.

costs allocated to non-IOU customers.[60] The modifications to the CAM proposed by Ms. Mara and Mr. Fulmer should be rejected in their entirety.

With regard to Ms. Mara's proposed two-step process for allocating CAM costs, SDG&E notes as a threshold matter that her proposal is based upon the flawed premise that "CAM procurement should be the exception, not the rule," and that the Commission's goal should be to minimize CAM procurement . . ."[61] Ms. Mara misstates the applicable law. It is the Commission's obligation under § 365.1(c) to allocate procurement costs in a manner that is "fair and equitable to all customers, whether they receive electrical service from the electrical corporation, a community choice aggregator, or an electrical service provider."[62] Contrary to the suggestion of Ms. Mara, the goal of the Commission's procurement authorization (or order) is not to shield particular market participants from cost, rather it is to ensure that identified reliability needs are met and that policy directives are satisfied by the utility procurement (or construction).

Moreover, Ms. Mara's proposed two-step process for allocating costs through the CAM is based on misguided analysis and unfairly shifts cost responsibility to ratepayers in contravention of § 365.1(c). Ms. Mara suggests, for example, that reliability is merely an "incidental" benefit conferred by IOU procurement, that IOU bundled customers alone are driving increases in peak demand or decreases in system load factors, and therefore that "[t]he IOU's bundled load obligation would be taken off the top of the overall system need."[63] Ms. Mara's analysis is overly-simplistic and ignores the fact, discussed above, that the IOU procurement authorized (or ordered) by the Commission confers an inherent

[60] AReM/DACC/MEA/Fulmer, AReM-1, pp. 38-43; 44-47, 47-48.
[61] AReM/DACC/MEA/Mara, AReM-1, pp. 5, 20 (emphasis in original).
[62] Pub. Util. Code § 365.1(c)(2)(B).
[63] AReM/DACC/MEA/Mara, AReM-1, pp. 28, 32.

and significant benefit on *all* customers in the IOU's distribution service territory. As Mr. Anderson explained, "the Commission has used the long-term planning process to determine how the energy and capacity needs of the IOU's bundled customers should be met [and], [f]or practical reasons and out of necessity, . . . has also relied upon the utilities to procure (or build) new generation resources where it has determined that resources are needed to meet utility loads *and, concurrently, other requirements*."[64]

Mr. Anderson observed further that "[p]rocuring (or building) new resources requires substantial long-term financial commitments. While non-utility load-serving entities could certainly make these commitments and develop the *bona fides* necessary to support the procurement of new resources, it is generally the case that the nature of their business models, based on relatively short-term customer commitments and the absence of binding obligations to serve beyond those assumed under contract, are not conducive to placing large amounts of capital at risk to serve customers with a propensity to migrate to other providers."[65] The IOUs have undertaken the burden of procuring new generation resources since, as Mr. Anderson noted, "this represents the most feasible method of assuring that needed new resources are added to the California electricity system."[66] He observed further, "[t]here is an intrinsic and inherent reliability benefit delivered by generation resources that is shared among and enjoyed by all consumers, whether they are bundled utility customers or not. The provision of these benefits justifies the allocation of costs to all consumers via the CAM."[67] Accordingly, Ms. Mara's proposed two-step CAM approval process should be rejected.

[64] SDG&E/Anderson, SDG&E-2, p.7.
[65] *Id.*
[66] *Id.*
[67] *Id.* at p. 4.

The CAM modifications proposed by Mr. Fulmer should likewise be rejected. Witness Fulmer proposes: (i) an adjustment to account for ancillary services to the proxy calculation for power purchase agreements ("PPAs") outlined in the Joint Parties' Proposal; (ii) modifications to the CAM charge for UOG; and (iii) adoption of a cap on costs allocated to non-IOU customers through the CAM.[68/] The rationale underlying Mr. Fulmer's proposed modifications is defective and adoption of the proposed modifications would result in subsidization of non-utility customers by utility ratepayer in direct violation of § 365.1(c).

With regard to the first of Mr. Fulmer's proposed CAM modifications, it is clear that Mr. Fulmer's analysis relies on flawed assumptions. Mr. Fulmer asserts that the Joint Parties' Proposal should be modified to include all major ancillary service products that are currently available in the ISO market, including such ancillary services as regulation, spinning reserve and non-spinning reserve. As Mr. Anderson explained, however, Mr. Fulmer's analysis and conclusions are misguided for two primary reasons: (i) the Joint Parties' Proposal's current assumption regarding valuation of included ancillary services is *already* generous,[69/] thus adoption of Mr. Fulmer's ancillary service modification would greatly over-estimate ancillary service revenues; and (ii) Mr. Fulmer bases his ancillary service valuation proposal on the incorrect assumption that a CAM unit will provide *every* ancillary product available in the ISO market. As Mr. Anderson pointed out, this is an invalid assumption:

[68/] AReM/DACC/MEA/Fulmer, AReM-1, pp. 38-43; 44-47, 47-48.

[69/] The Joint Parties Proposal assumes that plant would receive non-spin revenues based on its capabilities when the unit was not cost-effectively providing energy. The equation assumes the unit would earn these revenues in each and every hour it was capable of providing them. SDG&E/Anderson, SDG&E-2, p. 10.

> Mr. Fulmer's assumption that a CAM unit will provide *every* ancillary product available in the CAISO market (and should therefore be valued as such) is misplaced; Mr. Fulmer offers no verifiable data demonstrating the likelihood that a unit will win in each one of the specified ancillary service auctions. In order to provide ancillary services such as regulation up, regulation down and spinning reserve, the unit would have had to have been operating, thus it would have been economic in the energy market. This alone would limit the number of hours it would even be able to offer certain services. Also, to provide service like regulation up and spinning reserve the unit would have to be loaded at a point other than full load. If the energy benefits are based on the plant being fully loaded, there is no additional capacity available for regulation up and spinning reserve. As Mr. Fulmer notes, regulation up and down markets average only 350 MW an hour. However, given that there are likely to be substantial resources available to provide this service in any hour, the likelihood that the CAM unit would win in each and every hour is extremely low.[70]

Mr. Fulmer's proposed modification of the CAM charge related to UOG is equally problematic. Section 365.1(c)(2)(C) requires that the "annual revenue requirement" for UOG be used for purposes of calculating the net capacity costs to be allocated under the CAM where utility resources are used. Mr. Fulmer asserts that the annual revenue requirement for a UOG must be analogous to the costs of a PPA, and therefore that an annual <u>levelized</u> revenue requirement, rather than the actual yearly revenue requirement collected by the utility, should be allocated through the CAM.[71]

Mr. Fulmer's proposal is unsupportable and should be rejected. There is no mention in § 365.1(c)(2)(C) of a <u>levelized</u> revenue requirement and such a requirement would represent a significant departure from the plain language of the provision. The California Supreme Court has held that "[i]f there is no ambiguity in the language of the statute, then the Legislature is presumed to have meant what it said, and the plain meaning of the language governs. Where the statute is clear, courts will not interpret

[70] *Id.* at p. 11 (emphasis in original).
[71] AReM/DACC/MEA/Fulmer, AReM-1, pp. 46-47.

away clear language in favor of an ambiguity that does not exist."[72] Here, the plain language of the statute bars Mr. Fulmer's proposal to base UOG net capacity costs on the annual levelized revenue requirement associated with the UOG. Moreover, the data presented by Mr. Fulmer makes clear that requiring that the annual revenue requirement be levelized for CAM purposes would disadvantage ratepayers during the initial years of operation of the asset, and Mr. Fulmer failed to address a scenario in which the asset is not available for the entire anticipated plant life.[73] Thus, in addition to being unlawful, Mr. Fulmer's UOG cost allocation proposal would harm utility ratepayers and should therefore be rejected on policy grounds.

Finally, Mr. Fulmer's recommendation that the Commission adopt a cap on costs allocated through the CAM is unlawful and must be rejected. First, there exists no indication that the Legislature intended that a cap be placed on costs allocated through CAM. Indeed, the plain language of the statute *requires* that costs be allocated to all customers in an IOU's service territory that benefit from IOU procurement. Adoption of Mr. Fulmer's proposed cap could result in a circumstance where a non-utility customer receives a benefit without corresponding allocated cost. This outcome is clearly prohibited under § 365.1(c).

In addition, Mr. Fulmer's stated rationale for imposition of a cap – that "the net capacity cost calculations . . . may be faulty and systematically result in higher that reasonable net capacity costs," and that "unfair and inequitable costs could be imposed on CCA and DA customers"[74] – lacks merit. Mr. Fulmer fails to provide *any* credible evidence of improper costs being imposed on any CAM participant and entirely ignores

[72] *Lennane v. Franchise Tax Board*, 9 Cal. 4th 263, 268 (1994).
[73] *See* AReM/DACC/MEA/Fulmer, AReM-1, p. 46, Figure 1.
[74] *Id.* at pp. 47-48.

the role of the Commission in ensuring equitable allocation of costs. Procurement costs are subject to CAM only where the Commission has found that the specific resource fills a system or local resource need and will provide benefits to all customers in an IOU's service territory. Approval of a PPA that will be subject to CAM includes an evaluation as to whether the PPA costs are reasonable; likewise, in the case of UOG, costs are reviewed as part of the application for approval of the resource and also in the utility's general rate case.[75] Thus, the cap on CAM costs proposed by Mr. Fulmer is unnecessary and contrary to law, and should be rejected as such.

***C. Should Load Serving Entities (LSEs) be Able to Opt Out of CAM?***

Ms. Mara proposes that an LSE that makes a showing that it has procured adequate generations resources for a five-year period be permitted to "opt out" of the CAM and be entirely exempted from CAM charges.[76] Ms. Mara's proposal should be rejected as ill-conceived and impractical. First, by its terms, the CAM applies only to "generation resources that the commission determines ***are needed to meet system or local area reliability needs <u>for the benefit of all customers</u> in the electrical corporation's distribution service territory***."[77] Thus, by definition, the CAM is used *only* when the Commission has determined that that the benefits of a given resources extend beyond the IOU's bundled customers. As Mr. Anderson pointed out, "since other LSEs are benefitting from the IOU's procurement, they should not be permitted to opt out of the CAM in favor of receiving a 'free ride' at utility ratepayer expense."[78]

[75] SDG&E/Anderson, SDG&E-2, pp. 12-13.
[76] AReM/DACC/MEA/Mara, AReM-1, p. 54.
[77] Pub. Util. Code § 365.1(c)(2)(A) (emphasis added).
[78] SDG&E/Anderson, SDG&E-1, pp. 11-12.

Second, an opt out mechanism would, as a practical matter, be difficult to implement and would create additional program complexity. As Ms. Mara admitted during the evidentiary hearing held in the proceeding, the only circumstance in which the Commission could allow an LSE to opt out is if the party provides resources that meet the exact needs, terms and conditions that have been identified by the Commission in determining that the CAM should be applied.[79/] As the Commission has acknowledged, the requirement to provide a resource that meets the exact need, terms and conditions identified would present a challenge for non-IOU LSEs. In deciding against inclusion of an opt out provision in the CHP settlement, for example, the Commission noted its concerns regarding the ability of non-IOU LSEs to procure the specific CHP resources needed (as well as the administrative burden inherent in placing that procurement obligation on non-IOU LSEs).[80/]

In addition, adoption of the opt out proposal would shift the burden of developing new generation to utility ratepayers. Although Ms. Mara suggested that non-utility LSEs would be prepared to procure new generation resources if the need identified by the Commission was for such resources,[81/] her testimony during the evidentiary hearing belies this claim. She clarified during the hearing that "[t]he five-year contract would have to be the period of time from which the unit started producing to the end of the five years."[82/] In other words, the start date of the contract would be coincident with the start date of the CAM resource.[83/]

[79/] AReM/DACC/MEA/Mara, Tr. Vol. 6, pp. 1146-1147; Tr. Vol. 7 1165-1166.
[80/] D.10-12-035, *mimeo*, p. 56.
[81/] AReM/DACC/MEA/Mara, Tr. Vol. 7, p. 1165.
[82/] *Id.* at pp. 1167-1168.
[83/] AReM/DACC/MEA/Mara, Tr. Vol. 6, p. 1145.

Ms. Mara acknowledged during the hearing that it would not be possible in the current environment for a developer to obtain financing for new generation with a forward commitment of five years.[84/] Thus, in order to support new construction, a contract term of longer than five years is necessary. Although Ms. Mara noted that under her proposal "the 5-year [contract term] is a minimum," and that "[l]onger-term contracts would be equally acceptable," she admitted during the hearing that she is generally unfamiliar with resource adequacy transactions and was unable to address whether the members of AReM and MEA are typically willing enter into resource adequacy contracts with a term longer than one year.[85/]

It is reasonable to assume that these parties, and indeed most non-IOU LSEs, would not be willing to enter into longer-term contracts, and would be particularly reluctant to enter into contracts with the 20-year term that is standard for IOUs, which are generally considered to be a pre-requisite to financing new construction. As Mr. Anderson testified, "[p]rocuring (or building) new resources required substantial long-term financial commitments," and non-IOU LSEs have historically been unwilling to place large amounts of capital at risk to support procurement of new resources given the nature of their business model, which involves relatively short-term customer commitments and a lack of a binding obligations to serve beyond contractual requirements.[86/] Thus, as a practical matter, the opt out proposal would be exercised mainly (if not exclusively) in instances where existing generation was available to meet LCR need. This would mean that the burden of procuring new resources would fall solely to ratepayers.

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84/ AReM/DACC/MEA/Mara, Tr. Vol. 7, pp. 1172-1173.
85/ AReM/DACC/MEA/Mara, AReM-1, p. 56; Tr. Vol. 6, pp. 1135-1136.
86/ SDG&E/Anderson, SDG&E-2, p. 7.

Finally, Ms. Mara's proposal is poorly-conceived and lacks essential detail. The proposal fails, for example, to specify what showing an LSE would be required to make in order to opt out, deferring development of that (rather essential) aspect of the opt out proposal to the Commission.[87] Similarly, the proposal does not make clear, and Ms. Mara was unable to address at the hearing, what measures would be taken if an LSE that opts out of the CAM fails to comply with its resource adequacy requirement:

> Q. Do you think it would be reasonable that if there were to be reliability problems that resulted from noncompliance by an LSE, with this opt out that you propose, that those consequences be allocated entirely to that LSE?
>
> A. I haven't thought about that. So I guess without more thought I wouldn't really want to weigh in on that at this time.[88]

Ms. Mara offered the vague assurance that "some kind of enforcement mechanism" would be developed as "part of whatever the Commission determines at the time," and that any impact on reliability could be dealt with through demand response or "you can roll in the units on flat bed trucks."[89]

Ms. Mara's somewhat flip response to the important question of reliability impacts associated with her opt out proposal highlights the ill-considered nature of the proposal. From the details that *are* provided, it is clear that the proposal is deeply flawed and would almost certainly have a negative impact on utility ratepayers. The opt out proposal as it is described by Ms. Mara is plainly not viable, and should be rejected by the Commission.

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[87] AReM/DACC/MEA/Mara, Tr. Vol. 7, pp. 1169.
[88] *Id.* at pp. 1171.
[89] *Id* at p. 1170.

## VII.
## OTHER ISSUES

### *C. SCE Statewide Cost Allocation Proposal*

While declining to offer a concrete proposal for Commission consideration, SCE witness, Colin Cushnie, described SCE's current thinking regarding statewide allocation of costs associated with procurement of a resource with incremental flexibility benefits.[90/] Mr. Cushnie explained that if it is ordered by the Commission to procure a resource that offers flexibility benefits, SCE might elect to seek statewide allocation of the cost differential between a least-cost, non-flexible resource that would meet its LCR need, and the more expensive Commission-authorized resource that provides a flexibility benefit.[91/]

Mr. Cushnie described the four conditions that might prompt SCE to seek this allocation of costs:

(i) An explicit Commission direction to SCE to seek a resource with flexibility attributes;

(ii) A "significantly higher" cost associated with the flexible resource as compared against a non-flexible resource that would satisfy SCE's LCR need;

(iii) The resource increases the amount of flexible local generation available in the ISO's system; and

(iv) There is a system benefit provided to other Commission-jurisdictional customers.[92/]

While the discussion of statewide allocation of flexibility-related costs presented by Mr. Cushnie is conceptual in nature and lacks the necessary detail to be considered as a fully-developed proposal, SDG&E submits that even as a high-level concept, SCE's

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[90/] SCE/Cushnie, Tr. Vol. 4, p. 712 ("We haven't actually made a proposal to do this. We just wanted to put parties on notice, including the Commission, that to the extent that Edison was pushed into the higher cost LCR option to acquire flexible resources, that we would probably seek to allocate the cost difference."); *see also* p. 713 ("Again, we don't have a specific proposal.").

[91/] SCE/Cushnie, Exh. SCE-1, p. 26; SCE-2, pp. 5-6; Tr. Vol. 4, pp. 702-717.

[92/] SCE/Cushnie, Tr. Vol. 4, p. 712.

notion is deeply flawed and must be rejected. First, SCE cites no statutory authority for the contemplated allocation. It is clear that authority does not reside in § 365.1(c), which permits an IOU to procure generation to meet system or local area reliability need only on behalf of customers located in *its own* distribution service territory, and likewise to allocate the net capacity costs of such generation only to benefitting customers located in *its own* distribution service territory.[93/] Thus, SCE has no authority to procure resources to meet a system or local area reliability need on behalf of customers located in the service territories of SDG&E or Pacific Gas & Electric Company ("PG&E"), or to allocate costs of such procurement to customers of SDG&E or PG&E. Rather, SCE's procurement of resources to meet system or local reliability need is undertaken solely on behalf of customers located in *its own* service territory, and the resulting costs may be recovered only from those customers.

Moreover, SCE's allocation concept is inequitable and should be rejected on policy grounds. It is beyond dispute that the characteristics of the electric system are changing, and that the need to integrate increasing levels of renewable resources dictates that system planners look to newer technologies that provide the flexibility the system needs. Indeed, the Commission has ordered SDG&E to procure "dispatchable ramping resources that can be used to adjust for the morning and evening ramps created by the

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[93/] Pub. Util. Code § 365.1(c)(2)(A). The provision directs the Commission to:

> Ensure that, in the event the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, ***an electrical corporation*** to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in ***the electrical corporation's*** distribution service territory, the net capacity costs of those generation resources are allocated on a fully nonbypassable basis consistent with departing load provisions as determined by the commission, to all of the following:
>
> (i) Bundled service customers of the electrical corporation.
> (ii) Customers that purchase electricity through a direct transaction with other providers.
> (iii) Customers of community choice aggregators.

intermittent types of renewable resources."[94/] In recognition of the need for flexible benefits, SDG&E has for some time included the flexibility attribute in its solicitations for new local capacity. Mr. Anderson described SDG&E's approach to flexibility procurement during the evidentiary hearing held in this proceeding: "[A]s you're looking to add new resources to meet an LCR need . . . you get them such that they include the flexibility that the ISO will need to meet its flexibility needs."[95/] He explained that "[w]hen SDG&E looked to fill its local need, we specified that we wanted to make sure the units were flexible for lots of dispatchability needs."[96/] He noted further, "it doesn't make sense to us to go get a bunch of resources to meet an LCR need which have no flexibility to them whatsoever and then have to do additional procurement to meet flexibility need."[97/]

Mr. Anderson pointed out that while the precise requirements related to flexibility have not yet been defined, one can intuitively judge whether a unit is flexible.[98/] While he questioned Mr. Cushnie's claim regarding the likelihood of "significant" cost associated with the flexible resource – observing that there exists little concern "that specifying [a need for flexible resources] will end up in essence getting the wrong unit"[99/] – to the extent SDG&E has experienced such additional flexibility-related LCR cost, it has not sought to recover payment from customers located in the distribution service territories of SCE or PG&E.[100/] Indeed, in each such instance of procurement of a flexible resources, SDG&E has sought to allocate costs *only* to the benefitting customers

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94/ D.07-12-052, *mimeo*, page 110.
95/ SDG&E/Anderson, Tr. Vol. 7, p. 1211.
96/ *Id.* at p. 1213.
97/ *Id.* at pp. 1211-1212.
98/ *Id.* at pp. 1212-1213.
99/ *Id.* at p.1213.
100/ *See, e.g.,* SDG&E/Cushnie, Tr. Vol. 4, p. 715 (noting that a mechanism for inter-IOU allocation of incremental flexibility costs does not currently exist).

located in *its own* distribution serve territory, in accordance with the requirements of § 365.1(c)(2)(A).

Mr. Cushnie's discussion of SCE's statewide allocation concept fails to acknowledge or account for the system benefits provided to customers located in SCE's distribution service territory by SDG&E's past procurement of flexible resources. Nor does it explain SCE's rationale for declining to undertake similar procurement of resources with flexibility benefits, given the obvious need that exists. Although, as noted above, Mr. Cushnie made clear though his testimony at the hearing that SCE is not proposing in the instant proceeding adoption of a statewide allocation mechanism for costs related to the flexibility benefit, SDG&E urges the Commission to make clear in the final Track I decision issued in this proceeding that both § 365.1(c)(2)(A) and fundamental principles of equity preclude adoption of such a mechanism.

## VIII. CONCLUSION

In determining local reliability needs, the Commission should give weight to the recommendations of the ISO and should take a conservative approach to assumptions regarding available resources in order to ensure that pursuit of environmental goals does not serve to compromise system reliability. In addition, analysis of local reliability needs in the Los Angeles Basin should include consideration of the resources that are available in the San Diego area in order to determine the overall least-cost and best-fit approach that will ensure that the full 2500 megawatts flows on Path 44 during critical contingency conditions. Finally, for the reasons set forth herein, the Commission should continue to apply the existing CAM, with the modifications proposed by SDG&E, and should reject the CAM modifications proposed by AReM/DACC/MEA.

Dated this 24th day of September, 2012 in San Diego, California.

Respectfully submitted,

*/s/ Aimee M. Smith*
AIMEE M. SMITH
ALVIN S. PAK

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

Attorneys for
SAN DIEGO GAS & ELECTRIC COMPANY