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 12-03-014 (Filed March 22, 2012)

OPENING BRIEF OF THE UTILITY REFORM NETWORK ON TRACK 4 ISSUES

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I. INTRODUCTION

In accordance with Rule 13.11 of the Commission's Rules of Practice and Procedure, The Utility Reform Network ("TURN") submits this Opening Brief on the Track 4 issues related to the retirement of the San Onofre Nuclear Generating Station ("SONGS"). TURN's positions are based in large part on the Prepared Testimony (opening and rebuttal) of TURN's expert witness, Kevin Woodruff,[1] as well as the additional record developed during the Track 4 evidentiary hearings. Proposed Findings of Fact and Conclusions of Law reflecting TURN's positions are set forth in Appendix A of this brief.

II. SUMMARY OF TURN'S POSITIONS

TURN summarizes its Track 4 positions by reference to the five questions set forth by Administrative Law Judge ("ALJ") Gamson in his November 4, 2013 instructions for briefs.

1. *Should the CPUC authorize SCE and/or SDG&E to procure additional resources at this time for the purposes within the scope of this proceeding?*

Yes.

2. *If so, what additional procurement amounts should be authorized at this time? Please specify any calculation that leads to this position.*

TURN recommends that Southern California Edison ("SCE") and San Diego Gas and Electric ("SDG&E") each be authorized to procure up to 500 MW, plus or minus ten percent (±10%), on an "all source" basis for the purposes of meeting local reliability needs in the Western LA Basin (LA Basin) and San Diego Local Reliability Areas ("LRAs") within their respective service territories.[2]

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[1] Mr. Woodruff's opening testimony is Exhibit (Ex.) TURN-1 and his rebuttal testimony is Ex. TURN-2.
[2] TURN suggests the 500 MW authorization be subject to a "plus or minus ten percent" or similar range to accommodate the potential "lumpiness" of transmission or generation investments. TURN notes that

TURN makes this recommendation because the evidence in the record shows that substantial new investments in resources will quite likely be necessary within the next decade to maintain reliable electric service in the two LRAs and that procurement of such resources should thus begin as soon as reasonably possible. TURN generally endorses the utilities' proposals to procure approximately 500 MW on an "all source" basis as a means for starting such procurement.[3]

However, TURN does not think it wise to authorize SCE and SDG&E to procure the full amounts of their potential resource needs at this time, in the event that the Commission finds that such needs exceed 500 MW. Substantial uncertainties persist regarding the amounts of these needs and alternatives for meeting such needs. More generally, no clear best or even "better" means for meeting such future needs is evident at this time. These uncertainties argue for the Commission to take a measured approach toward authorizing additional commitments of customers' dollars.

Further, should the Commission find that need in a local area is less than 500 MW, the Commission should only authorize procurement to meet such lower need in that local area.

One determinant of local need deserves the Commission's particular attention. TURN believes the Commission should explicitly decline to authorize procurement of resources to meet a finding of need that is dependent on the assumption that "load shedding" may not be used to mitigate the N-1-1 "Sunrise/SWPL" contingency that drives need in both the LA Basin and San Diego LRAs. Rather, the Commission should defer any resource authorization based on this

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SDG&E has requested authority to purchase from 500 to 550 MW of local capacity. (Ex. SDG&E-1, p. 5:1-5 and p. 12:5-6.)

[3] *Id*., as to SDG&E's request, and Ex. SCE-1, p. 3:14-20 and pp. 55:1-58:10, as to SCE's request.

remote possibility until a thorough benefit-cost analysis is completed and the CAISO's coming stakeholder process on this issue is concluded.

3. *What additional resources, if any, should be authorized to fill procurement needs? Should there be any requirements or restrictions on procurement amounts for any specific resources or categories of resources?*

For purposes of the up to 500 MW, ±10%, procurement that TURN recommends above, each utility should select additional authorized resources from among all resources capable of meeting local reliability needs in the LA Basin and San Diego LRAs, whether such resources are conventional or preferred.

4. *What process should the utilities use to fill any procurement amounts authorized at this time?*

As a general matter, TURN strongly prefers that the IOUs hold competitive Requests for Offers ("RFOs") to solicit the broadest possible set of proposals to meet such needs. However, TURN does not necessarily oppose highly cost-effective proposals with third-party suppliers that are reached through bilateral negotiations.

5. *Are there other determinations the CPUC should consider, or conditions the CPUC should impose, regarding Track 4 procurement?*

The Commission should find that any procurement it authorizes in this Track 4 is for the purpose of maintaining reliable service in the LA Basin and San Diego LRAs, and that the net benefits and costs of the resulting capacity should be allocated to all customers pursuant to the Cost Allocation Mechanism ("CAM"). It is premature at this time to determine how to allocate the costs of the other reliability proposals the utilities discuss in their testimony but have not yet proposed.

The positions summarized in questions 1 through 3 and 5 are discussed more fully in the following sections of this brief.

III. THE COMMISSION SHOULD AUTHORIZE UTILITIES TO PROCURE UP TO 500 MW OF NEW LOCAL RESOURCES ON AN 'ALL SOURCE' BASIS

The retirement of SONGS has apparently led to a need for significant investment in various resources to maintain reliable electric service in the LA Basin and San Diego LRAs.[4] Quick action to begin addressing such needs is warranted.[5] TURN thus supports each utility's request for authorization to procure no more than 500 MW, ±10%, on an "all source" basis to meet such needs.[6] *Should the Commission find that need in a local area is less than 500 MW, the Commission should only authorize procurement to meet this lower need in that local area.*

However, TURN cautions the Commission against authorizing all the needs the utilities and CAISO have postulated in their various testimonies, even if the Commission finds that such needs exceed 500 MW. Given the many uncertainties regarding future loads and the availability of resources, there is no clear best or even "better" means for meeting such needs.[7] For example, with respect to meeting local needs, SCE will be proposing a "Living Pilot" to solicit and assess non-conventional and preferred resources to meet specific local needs;[8] the results of such a commendable experiment should inform future procurement efforts in the area. Potential delays in the retirement of certain units relying on Once-Through Cooling (OTC) technology might also

[4] Ex. ISO-1, Tables 9 to 13 (pp. 19-26), Ex. SDG&E-3, Tables 1 to 3 (pp. 10-12) and Ex. SCE-1, Table III-5 (p. 32). In citing these sources, TURN is not necessarily agreeing with the specific findings therein.
[5] Ex. TURN-1, p. 3:8-16 and p. 9:14-10:3.
[6] Ex. SCE-1, p. 3:14-20 and pp. 55:1-58:10 and Ex. SDG&E-1, p. 5:1-5 and p. 12:5-6. As noted above, SDG&E requested to procure in a range of 500 to 550 MW and TURN suggests the 500 MW authorization be subject to a "±10%" or similar range to accommodate the potential "lumpiness" of transmission or generation investments.
[7] Ex. TURN-1, p. 2:11-19 and pp. 4:11-10:3 and Ex. ISO-7, p. 5:13-15.
[8] Ex. SCE-1, p. 4:19-20 and p. 49:1-54:11.

meet need at low cost on an interim basis,[9] particularly given that SONGS's retirement has already mitigated much of the aggregate environmental impacts of OTC units.[10] And it is conceivable that future transmission planning efforts by the two utilities and the CAISO will identify additional transmission projects or other measures that can meet local need more cost-effectively.[11] These uncertainties argue for the Commission to take a measured approach toward authorizing additional commitments of customers' dollars.

As discussed in the following section, the Commission should also explicitly refrain from authorizing any procurement to meet local needs that presumes load shedding is not available to mitigate the extremely unlikely N-1-1 Sunrise/SWPL contingency that is driving local needs in both the LA Basin and San Diego LRAs.

IV. THE COMMISSION SHOULD NOT AT THIS TIME AUTHORIZE ANY PROCUREMENT BASED ON THE ASSUMPTION THAT LOAD SHEDDING SHOULD NOT BE USED TO MITIGATE THE N-1-1 CONTINGENCY DRIVING LOCAL NEEDS

A key driver of local reliability need in both the LA Basin and San Diego LRAs is the CAISO's assumption that load shedding should not be used to mitigate the impacts of the N-1-1 contingency (overlapping outages of the Sunrise Powerlink (Sunrise) and Southwest Powerlink (SWPL) transmission lines) that drives the need estimates provided in this docket .[12] However, as discussed below, the use of this assumption is entirely discretionary, is not well-documented or formally approved by the CAISO, and may well impose costs on SCE and SDG&E ratepayers that are not justified by the incremental reliability benefits for such a remote contingency.

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[9] Ex. ORA-5, pp. 9:7-11:9.
[10] Ex. SCE-1, p. 22, particularly footnote 76.
[11] Ex. ISO-1, pp. 30:27-31:7.
[12] Ex. TURN-1, p. 13:6-13 and Ex. ISO-1, p. 6:11-13.

National and regional planning criteria allow the CAISO to use load shedding to mitigate an outage such as the key N-1-1 contingency in this case.[13] The CAISO justifies its decision not to consider load shedding in the case of the Sunrise/SWPL outage based on a qualitative analysis of such factors as the amount of load that could be shed, the urban nature of such load, the importance of the Imperial Valley substation, and the challenges of conducting a benefit-cost analysis in such an area.[14]

The CAISO's explanations for rejecting load shedding outright and not conducting a more complete analysis, including a quantification of the benefits and costs of allowing load shedding as a mitigation measure, are unpersuasive. CAISO witness Sparks testified on the stand that the CAISO has 34 Special Protection Schemes ("SPS's") in place that allow it to shed load as a means of managing specific contingencies.[15] The CAISO also has a Benefit-Cost analysis methodology in place for deciding when such load shedding may be justified[16] that it declined to use in analyzing mitigation for the Sunrise/SWPL outage because of the complexity of the modeling in the relevant local areas.[17] But the CAISO has admitted that its criteria for applying this methodology and assessing load shedding in such cases are not part of the

[13] Ex. TURN-1, 23:13-24 and Appendix A. See also Ex. ISO-2, 5:1-4.
[14] Ex. TURN-1, 23:26-24:27, Ex. ISO-2, 5:22-6:18 and Ex. ISO-7. 8:24-9:25 and 10:8-11:2.
[15] Though Mr. Sparks did claim that none of these SPS's were comparable to load shedding for the N-1-1 contingency at issue in this case. Reporter's Transcript (RT), pp.1582:6--1588:23 (Sparks, CAISO) and Ex. TURN x ISO-6. The information in these sources appears to contradict the information provided in Ex. ISO-2, p. 5:12-20.
[16] Ex. ISO-6, pp. 5-6 and 12-14.
[17] Ex. ISO-7, pp. 10:8-11:2 and RT, pp. 1432:22-1436:18 (Sparks, CAISO) and pp. 1621:13-1625:24 (Millar, CAISO).

CAISO's planning standards[18] and are not well-documented.[19] In fact, the CAISO has proposed to start a stakeholder process to clarify its criteria in early 2014.[20]

Further, despite the CAISO's assurance that its "Board of Governors is aware of the ISO's historic practices in regard to the consideration of the N-1-1 contingencies",[21] CAISO staff communications with the Board on this issue are scant. For example, in response to a TURN data request for such communications, the CAISO provided presentations that barely mentioned the topic.[22] The Commission is fully justified in waiting for the CAISO to review its own standards, without presupposing a particular outcome for that process, before acting to commit ratepayer dollars based on this assumption.

The Commission also has the option to consider the use of load shedding to mitigate the overlapping Sunrise/SWPL outage contingency on a temporary basis, rather than assuming that such a load shedding scheme should be permanent. That is, the Commission could decide to rely on a load shedding scheme for a limited number of years until the best possible capital investment plan for maintaining reliability is determined. Office of Ratepayer Advocates' ("ORA") witness Fagan proposed this potential use of load shedding[23] and CAISO witness Sparks noted that load shedding schemes are already used in this manner elsewhere in the CAISO system.[24]

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[18] Ex. ISO-7, p. 10:3-6.
[19] RT, p. 1434:11-17 (Sparks, CAISO).
[20] Ex. ISO-7, p. 10:3-6 and RT, p. 1632:8-28 (Millar, CAISO).
[21] Ex. ISO-7, p. 2-3.
[22] Ex. TURN x CAISO-5 and RT, pp. 1630:19-1632:7 (Millar, CAISO).
[23] Ex. ORA-3, pp. 11:15-27.
[24] Ex. ISO-2, p. 5:11-20.

A. Preliminary Benefit-Cost Analysis Suggests That Allowing Load Shedding Would Likely Be Beneficial to Customers

The CAISO staff rationales for not performing benefit-cost analysis allowing load shedding to mitigate the overlapping Sunrise/SWPL outage are unpersuasive. The CAISO testified that assessing the benefits and costs of load shedding would require performing a substantial number of assessments of other contingencies in the LA Basin and San Diego areas.[25] Yet the only evidence provided in this case suggests that the key difference in the assessment of the benefits and costs of load shedding is the difference in local needs under the "N-1-1, no load shedding" contingency and the "G-1, N-1" contingency in San Diego.[26] The additional "needs" caused by the "no load shedding" assumption are thus easily quantified.[27] These impacts are summarized in Table 1 below for each of the utilities' analytic scenarios.

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[25] Ex. ISO-7, p. 10:8-11:2 and RT, pp. 1621:13-1625:24 (Millar, CAISO).
[26] Ex. TURN x ISO-3 and RT, pp. 1625:25-1628:15 (Millar, CAISO).
[27] In Ex. SDG&E-3, SDG&E witness Jontry presents "new generation requirements" under the "G-1/N-1 Reliability Criteria" on Table 1 (p. 10) and the same requirements under the "N-1-1 Reliability Criteria" on Table 2 (p. 11); his Table 3 (p. 12) compares the results of these criteria for both SDG&E and SCE. In Ex. SCE-1, SCE witness Chinn compares "new generation dispatch" for two of SCE's scenarios "with" and "without SDG&E Load Shed" at Table III-5 (p. 32), as documented in Table III-4 (p. 31)).

Table 1
Increase In Local Reliability Needs Due To Policy Not to Use Load Shedding
(MW)

UTILITY	**SCE a/**		**SDG&E b/**	
Scenario	Generation Only	Mesa Loop-In	Generation Only	IV - SONGS DC
SCE (LA Basin):	438	900		
SDG&E:			150	250

Source: Exhibit TURN-1, Table 3 (p. 14).

Notes:
a/ SCE did not provide "No Load Shedding" capacity estimates for its Preferred Resources and Regional Transmission scenarios.
b/ SDG&E's estimates showed load shedding assumption had no impact on "Devers- NCGen AC" scenario.

Given these estimates of the MW impact on need of the "no load shedding" assumption, it is possible to perform a preliminary benefit-cost analysis of the impact of this restriction on SCE customers based on the record evidence. Preparing such estimates requires estimating the net costs customers would incur to support the additional investment in capital and other programs to meet the above increment of need and comparing such costs to the benefits to customers of avoiding load shedding in the event the N-1-1 contingency occurs.[28]

SCE provided estimates of the net costs to customers of meeting local needs. As noted in TURN witness Woodruff's testimony, TURN is concerned that SCE's estimates may be

[28] Ex. IEP-2, pp. 14:9-16:12 and RT, pp. 2261:26-2262:16 and p. 2265:6-16 (Woodruff, TURN).

underestimated;[29] further, these costs also do not include the costs of meeting local need in San Diego. With these caveats, SCE's estimates for 2022 are shown in Table 2 below.[30]

Table 2

Increase In SCE Customer Costs In 2022 Due To Policy Not To Use Load Shedding
($ Million)

		SCE Scenario					
		LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission	Row ID:	Sources:
LA Basin Need, w/ Load Shed	MW	2,802				A	1/
Total Net Cost to Meet Need in 2022	$million	339	403	460	615	B	2/
Average Net Cost to Meet Need in 2022	$/kW	121	144	164	219	C	1000 x B / A
Higher LA Basin Need without Load Shed	MW	436	900	900	900	D	1/
Higher Cost without Load Shed in 2022	$million	53	129	148	197	E	C x D / 1000

Sources: 1/ Ex. TURN-1, Table 4 (p. 17). SCE did not estimate impactof "no loadshedding" assumption on PreferredResources and Regional Transmission scenarios.

2/ "Total Net Cost" for year 2020 from pages 65, 67, 70 and 72 of Ex. SCE-3 (which are pages 20, 22, 25 and 27 of portion of Ex. SCE-3 titled "2012 Long-Term ProcurementPlan, Track 4, Southern CaliforniaEdison Company, Workpaper Supporting Net Indicative Cost Estimates", which begins on page 45 of Ex. SCE-3).

Row A of Table 2 shows SCE's computation of LA Basin need assuming load shedding is permitted and Row B shows SCE's costs of meeting such need under its four scenarios, again assuming load shedding is allowed. Row C shows the average net cost of meeting LA Basin need, which is simply the scenario-specific cost data shown in Row B divided by the need shown in Row A. The increase in LA Basin need if load shedding is not permitted is shown in Row D. The higher total net costs to SCE customers of not allowing load shedding is shown in Row E, and is simply the need in Row D times the average cost shown in Row C.

[29] Ex. TURN-1, pp. 21:7-22:6 and RT, p. 2098:5-28, pp. 2101:7-2102:6, pp. 2103:24-2104:9, pp. 2106:26-2107:21 and pp. 2172:14-2174:15 (Silsbee, SCE).

[30] The data shown in Table 2 are annual costs for the year 2020. Following years' costs are approximately equal to costs in year 2020. At Table 4 (p. 17) and Table 5 (p. 20) of Ex. TURN-1, TURN witness Woodruff also provided SCE's estimates of the Net Present Value of such net costs over the period of 2020 to 2032.

These annual costs should be compared to the potential annual benefits of avoided curtailments to customers, which are the estimated costs of a load shedding event times the probability such an event would occur during a year.[31] IEP witness Monsen estimated such benefits as $1 billion per event.[32]

The data in the record most pertinent to probability of a load shedding event are in a study SDG&E conducted in 2007 regarding the probability of combined Sunrise and SWPL outages. That study found that a simultaneous "N-2" outage of the Sunrise and SWPL lines had a probability of occurrence ranging from once every 21 to 928 years for both the original and the "alternative" Sunrise path that was ultimately approved.[33] Further, SDG&E's report – even though it conceded the probability of a double line outage on the alternative path was higher – still suggested that it was reasonable to assume the minimum likelihood of such an N-2 outage was no more than once in 30 years for either path, which was the threshold for reclassifying the N-2 outage as a Category D contingency.[34]

CAISO witness Sparks argued that the probability of an N-1-1 outage was as high as once per thirteen years, based solely on data included in the study provided as Exhibits TURN x CAISO-2 and TURN x CAISO-7.[35] Upon cross-examination, Mr. Sparks agreed that the single outage SDG&E identified in the thirteen years of data it analyzed was due to the washing of

[31] Ex. ISO-6, p. 14, Ex. IEP-2, p. 15:22-23 and RT, pp. 2264:20-2265:5 (Woodruff, TURN).
[32] Ex. IEP-2, p. 16:1-2 and RT, p. 2235:5-12 (Monsen, IEP).
[33] Ex. TURN x ISO-2, pp. 3, and Ex. TURN x CAISO-7, p. 56.
[34] Ex. TURN X ISO-2, pp. 2, and Ex. TURN X CAISO-7, p. 56 and 65. Though the comparisons of risk factors at pages 37 and 65, respectively, of these exhibits provides evidence that risks appear higher for the approved Alternative Path than the original path, there was no evidence that such risks for the Alternative path were "*trending* to one in 21 years, versus 928 years for the originally proposed Sunrise route" (Ex. ISO-2, 6:1-3, emphasis added).
[35] Ex. ISO-2, pp. 5:26-6:3 and RT, pp. 1436:19-1442:8 (Sparks, CAISO).

insulators and should not be considered as a potential double line outage.[36] As noted above, the study he cited actually estimated the outage risk as being between 21 and 928 years and concluded that the risk should be considered no more probable than once in 30 years regardless of which Sunrise route was analyzed. There is thus no evidence in the record to support Mr. Sparks's statement that outage risks should be assumed to be one in 13 years or that they "trended" to 21 years.[37]

The data in this record regarding potential benefits of avoided load shedding are shown in Table 3 below. IEP's estimate of $1 billion in benefits is divided by different record-based estimates of the annual frequency of such curtailments to provide alternative estimates of benefits that can be used for computing Benefit-Cost Ratios (BCRs).

[36] RT, 1438:3-1439:13 (Sparks, CAISO).
[37] While it may be theoretically conceivable that an N-1-1 outage would have a higher probability than an N-2 outage, TURN is not aware of any evidence in the record to support basing the Commission's decision on such a theoretical possibility.

Table 3
Annual Benefits Of Avoided Load Shedding
As A Function Of Probability Of Such Load Shedding
($ Million)

Frequency of Load Shedding	Annual Benefits of Avoided Load Shedding 1/
(# of years between load shed events)	($million/year)
21	47.6
30	33.3
100	10.0
300	3.3

Notes:

1/ Equals benefits of avoided load shedding of $1 billion per event, per Ex. IEP-2, 16:1-2 and RT, 2235:5-12 (Monsen, IEP), divided by number of years between load shed events.

BCRs of investments to avoid the need for load shedding to manage the N-1-1 contingency are computed from the costs in Table 2 and benefits in Table 3 and shown in Table 4. If an investment's benefits exceed its costs, its BCR will exceed 1.0. But none of the BCRs shown in Table 4 are greater than 1.0, and the only one even close to 1.0 is based on the pessimistic assumption that load shed events will occur once every 21 years *and* the unlikely assumption that the costs of meeting any extra need would equal the average costs of SCE's LA Basin Generation scenario. Thus, under this preliminary analysis, the investments to avoid load shedding in case of an N-1-1 contingency are not cost-effective for ratepayers.

Table 4
Benefit-Cost Ratio to SCE Customers Of Investments To Prevent Load Shedding As A Mitigation For Sunrise/SWPL Outage

	SCE Scenario			
Frequency of Load Shedding 2/ (# of years between load shed events)	LA Basin Generation	LA Basin Transmission	Preferred Resources	Regional Transmission
21	0.902	0.368	0.322	0.241
30	0.632	0.257	0.226	0.169
100	0.189	0.077	0.068	0.051
300	0.063	0.026	0.023	0.017

Note: Benefit-Cost Ratios are computed as benefits as a function of frequency of load shed events from Table 3 divided by costs per SCE scenario from Table 2.

TURN acknowledges that this analysis is only a first pass at this issue. For example, TURN expressed concerns above about SCE's cost estimates. TURN also believes IEP's benefit estimate is quite aggregated and does not reflect the detailed benefit data the CAISO says it considers when conducting such an analysis.[38] And these estimates are based only on the SCE's estimates of the added costs of planning to a standard that does not consider load shedding.[39]

As a general principle, TURN urges the Commission in its upcoming decision to <u>not</u> authorize the utilities to meet any needs that are based on the assumption that load shedding is

[38] Ex. ISO-6, p. 14.
[39] It is possible there are less costly solutions for SCE's customers than the four scenarios SCE postulated. For example, SDG&E's witness Jontry suggested that the potential need for load shedding in both SDG&E and SCE could be eliminated by the relatively more modest investment in 150 MW in generation in San Diego. (See Ex. SDG&E-4, p. 2:22-3:1 and RT, pp. 1714:25-1716:5 (Jontry, SDG&E), pp. 2017:27-2018:19 (Chinn, SCE), and pp. 2085:24-2086:20 (Chinn, SCE).) However, no party has presented in the record data showing that such other options would be cost effective.

unwarranted to mitigate the key N-1-1 contingency in this case. TURN is not proposing that the Commission make a "once-and-for-all" determination on this issue. Rather, the Commission should revisit this issue after the CAISO completes its stakeholder process and after additional information on the benefits and costs of means to meet local needs in the LA Basin and San Diego are gathered by the utilities' upcoming procurement and transmission planning efforts.

B. The Utilities Are Clearly Concerned With The Cost Implications Of The "No Load Shedding" Assumption

Commission deferral of authorizing any increment of need driven by the assumption that load shedding is not an acceptable mitigation for the key N-1-1 contingency is further supported by the utilities' (particularly SCE's) own obvious concerns with the added costs. Both utilities provided need results for their respective LRAs using both the "with" and "without" load shedding assumptions,[40] and SCE's cost analysis was based on the assumption that load shedding could be used as mitigation.[41] In addition, SCE's rebuttal testimony addressing parties' arguments in favor of allowing load shedding addressed some of the disadvantages of such a policy, but did not oppose load shedding; rather, SCE's testimony stated "load shedding should only be used judiciously as mitigation for contingencies," particularly in heavily populated areas. SCE also said that, "to the extent that specific general and/or localized criteria are adopted to avoid load shedding for Category C contingencies, the costs and benefits of such criteria should

[40] See footnote 27 above.

[41] Ex. TURN-1, 15:20-22. SCE's use of the "with load shedding" assumption to prepare its cost estimates can also be confirmed by comparing the total "new generation dispatch" for Scenarios 1, 2, 3 and 4 at Ex. SCE-1, Table III-5 (p. 32), which assume load shedding, to the amount of new CCGT and CT capacity assumed built in the LA Basin on Table 1 (p. 48) of Ex. SCE-3.

be comprehensively evaluated, and reasonable time lines for implementation of required system changes should be adopted".[42] TURN agrees.

In its rebuttal testimony, SDG&E chose to oppose the use of load shedding as a mitigation for the Sunrise/SWPL contingency.[43] However, SCE's witness Chinn stated that he understood SDG&E's rebuttal testimony to be a change in its original position – or at least its original modeling assumption – that load shedding should be allowed.[44]

The utilities have legitimate concerns about the cost implications of not using load shedding to mitigate the Sunrise/SWPL contingency. The Commission should defer authorizing procurement needed to meet needs driven specifically by this assumption.

C. The Commission Is Free To Use Load Shedding As a Modeling Assumption

The CAISO has argued that the Commission has already considered and decided the "no load shedding" assumption and that it is beyond the scope of this Track 4.[45] However, the ALJ rejected this argument in denying a CAISO motion to limit the scope of the Track 4 hearings.[46] Moreover, as a general principle, current Commissions are not bound by the actions of past Commissions.[47] Given the significant cost implications discussed above, the Commission should not reject the load shedding assumption in this docket, given that the Commission has previously held that it will not adopt a policy of "reliability at any cost".[48]

[42] Ex. SCE-2, pp. 15:1-16:19, especially p. 15:6-11.
[43] Ex. SDG&E-4, p. 1:15-21.
[44] Ex. SCE-2, p. 45:4-6 and RT, pp. 2023:28-2025:25 (Chinn, SCE).
[45] Motion of the California Independent System Operator Corporation to Limit Scope of Track 4 Evidentiary Hearing, October 18, 2013.
[46] RT, p. 361:4-6 (ALJ Gamson).
[47] RT, p. 361:9-11 (ALJ Gamson).
[48] D.05-10-042, p. 7.

Further, this Commission has previously accepted a higher likelihood of load shedding as a consequence of pursuing environmental and other policies. As the CAISO itself has noted, the CAISO warned the Commission in the Sunrise case that the environmentally-preferred Southern route would lead to a higher chance of load shedding than the Northern route,[49] yet the Commission approved the Southern route in part because the Northern route was encumbered with more environmental and other deficiencies.[50] The Commission can and should balance the costs and reliability benefits of the "no load shedding" assumption in deciding if and how much local capacity to authorize the utilities to procure.

D. The Commission Should Not Be Dissuaded By Exaggerated Talk of 'Blackouts'

In asking the Commission to defer action on approving procurement or investment to meet the additional needs implied by the "no load shedding" assumption, TURN is not proposing "blackouts" as an answer to LA Basin and San Diego reliability needs, as some may argue. Rather, TURN is asking the Commission to balance ratepayer benefits and costs, as the Commission has said it would do in analyzing reliability issues.[51] Using load shedding as a modeling assumption would save significant costs to residents and businesses to address a contingency that the record shows is extremely unlikely ever to occur. It would be poor policy to automatically rule out such an option. Further, the load shedding being discussed does not result in uncontrolled, indefinite blackouts; rather, such service interruptions can be managed to mitigate their impacts.[52]

[49] Ex. ISO-7, p. 9:1-3 and RT, pp. 1618:16-1619:10 (Millar, CAISO). See also Ex. SC-1, Exhibit 2, p. 1.
[50] D.08-12-058, Ordering Paragraph 1 (p. 292) and Finding of Fact 24 (p. 286).
[51] D.05-10-024, p. 7.
[52] Ex. TURN x SDG&E-1 and RT, pp. 1741:9-1742:5 (Jontry, SDG&E).

V. BENEFITS AND COSTS OF NEW RESOURCES AUTHORIZED PURSUANT TO THIS DECISION SHOULD BE ALLOCATED AMONG CUSTOMERS AND LOAD-SERVING ENTITIES PURSUANT TO THE COST ALLOCATION MECHANISM

The utilities – including Pacific Gas and Electric (PG&E) – have asked the Commission to apply the CAM to allocate the benefits and costs of any resources it authorizes SCE and SDG&E to procure in this Track 4.[53] TURN generally agrees with the utilities' positions on this issue.[54]

A. The Law Requires the Costs of Capacity Needed for Local Reliability to Be Allocated to All Customers

The Commission first adopted the CAM in 2006 to allocate the costs and benefits of new generation to all benefiting customers in the service territory of an IOU, primarily with the intent to promote contracts that would support the development of new generation needed for reliability.[55] The regulatory and statutory history of the CAM is summarized in Decision 13-02-015, the latest decision adopting changes to the CAM.[56]

The Legislature enacted SB 695 in 2009,[57] codified in Public Utilities Code §365.1(c)(2)(A), which *mandates* that the Commission allocate costs for local area reliability needs to all customers:

> (c) Once the commission has authorized additional direct transactions pursuant to subdivision (b), it shall …
>
> (2) (A) Ensure that, in the event that 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**

[53] Ex. SCE-1, 59:14-60:21, Ex SCE-2, 38:7-41:9, Ex. SDG&E-1, 12:16-13:18, Ex. SDG&E-2, 3:14-5:14 and Ex. PG&E-2, 6:6-7:19.
[54] Ex. TURN-2, 2:8-16.
[55] For example, D.06-07-029, p. 3-5, 11-12.
[56] See, D.13-02-015, Sec. 9.1, p. 98-101.
[57] Stats. 2009, ch. 337.

> **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.[58]

The statutory language is specific and direct. If the Commission determines that the generation resource is needed to "meet system or local area reliability needs for the benefit of all customers," then the Commission must allocate the capacity costs of the generation to all customers.

The only condition precedent which must be satisfied in this Track 4 so as to require cost allocation using the CAM is that the generation capacity be needed to "meet local area reliability needs." That condition is implicit in the very structure of this Track 4, and is distinct from the determination of the energy procurement needs for bundled customers, which occurs in a separate phase of the LTPP.[59]

B. The AReM/DACC Testimony Misstates Commission Policy

As noted by TURN witness Woodruff, the only substantive written testimony opposing the utilities' request – filed on behalf of the Alliance for Retail Energy Markets and the Direct Access Customer Coalition ("AReM/DACC") – fundamentally misconstrues Commission policy and provides no factual basis for the Commission to take any action in this case.[60]

During his appearance on the witness stand, AReM/DACC witness Mr. Rochman showed limited knowledge of and little regard for established Commission policy regarding the development of new resources needed to maintain reliable electric service. Mr. Rochman

[58] PU Code § 365.1(c) (emphasis added).
[59] Ex. TURN-2, p. 13:1-13, including footnote 29. See also, D.13-02-015, p. 4-6.
[60] Ex. TURN-2, pp. 8:16-13:13.

conceded that Direct Access (DA) and bundled customers suffered equally during system outages and that any measure that increased reliability for one group increased reliability for the other.[61] Yet Mr. Rochman argued that somehow utility investments in new generation would never benefit unbundled customers.[62] In fact, he could not offer <u>any</u> examples of resources that would benefit all customers and thus be subject to CAM.[63] Mr. Rochman also said he "did not care to testify" on the topic of how the Commission should "address the development of new generation that might take many years to plan."[64]

In sum, while Mr. Rochman agreed that bundled and unbundled customers share equally in the benefits of reliability, he relied on the contradictory and untenable assertion that utility investments in generation somehow do not provide reliability benefits to unbundled customers. In light of the absence of any sound basis for their position, the Commission should dismiss AReM/DACC's arguments that the CAM should not apply to any new procurement the Commission authorizes in this Track 4.

C. Application of CAM to Other Utility Reliability Programs Should Be Determined in Relevant Applications

The CAM should clearly apply to any procurement authorizations the Commission issues in this Track 4. However, the utilities have testified that they will propose additional measures to respond to local reliability needs in the LA Basin and San Diego LRAs.[65] As the details of these

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[61] RT, pp. 2217:10-2218:10 (Rochman, AReM/DACC).
[62] RT, p. 2207:9-19 (Rochman, AReM/DACC).
[63] RT, p. 2214:3-11 (Rochman, AReM/DACC).
[64] RT, p. 2210:11-19 (Rochman, AReM/DACC). Mr. Rochman also made a similar statement at RT, p. 2206:18-22.
[65] Ex. SCE-1, pp. 49-54, for description of the "Living Pilot," p. 61:1-62:10 for contingent Gas-Fired Generation (GFG) siting proposal, and p. 51:4-7 regarding SCE's intent to file applications for approval of the Pilot and the contingent GFG siting proposals. Ex. SDG&E-1, pp. 16:9-17:10, regarding SDG&E's "energy park" proposal.

additional utility efforts to meet local needs are not known at this time, the Commission should defer consideration of the use of CAM or similar mechanisms to allocate such efforts' benefits and costs until the utilities file applications proposing such additional measures.[66] However, the Commission would do well to specify that any such future consideration of CAM policy will be based on established state law and Commission policies, and not the policies that AReM/DACC wish were in effect.

VI. CONCLUSION

For the reasons set forth in the testimony of Mr. Woodruff and in this brief, the Commission should adopt the Track 4 recommendations summarized in Section II and the Findings of Fact and Conclusions of Law set forth in Appendix A.

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Respectfully submitted,

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[66] Ex. TURN-2, p. 16:1-17.

APPENDIX A

Proposed Findings of Fact and Conclusions of Law

Findings of Fact:

1. Substantial new investments in resources will quite likely be necessary within the next decade to maintain reliable electric service in the two local reliability areas (LRAs) and procurement of such resources should begin as soon as reasonably possible.
2. Substantial uncertainties persist regarding the amounts of the utilities' resource needs and alternatives for meeting such needs, and no clear best means for meeting such future needs is evident at this time.
3. Ruling out load shedding as an alternative for mitigating the N-1-1 contingency driving the local reliability needs being analyzed in this Track 4 would potentially cause a significant increase in costs to ratepayers to address an extremely remote contingency.
4. The new resources that will be procured as a result of this Track 4 decision will meet local area reliability needs for the benefit of all customers of Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E).

Conclusions of Law:

1. Authorizing SCE and SDG&E to procure up to 500 MW of additional local resources, plus or minus 10 percent, on an "all source" basis would allow the utilities to take significant yet measured steps to meet local reliability needs.
2. At this time, the option of load shedding should be retained as an alternative for mitigating the N-1-1 contingency driving estimates of local reliability needs in this Track 4.
3. The benefits and costs of resources procured pursuant to this Track 4 should be allocated to all customers in the service territories of SCE and SDG&E in accordance with the Cost Allocation Mechanism.